conversion to dry ash handling or cessation of operations is a requirement of CAMA, which was enacted in 2014, and, thus, the ELG Rule, which was not promulgated until 2015, was not the driver of this outcome in North Carolina. Tr. Vol. 26, p. 743.

Witness Junis disagreed with Company witness Kerin's testimony that DEC had not done anything to cause it to incur any unjustified coal ash-related costs, and he disagreed with witness Wright's minimization in his testimony of the role of the Dan River spill on the enactment of CAMA. Tr. Vol. 26, pp. 743-44. He stated that Dan River spill "was a large contributing factor to the creation of CAMA, which forced the Company to take expensive corrective actions." Tr. Vol. 26, p. 744. He further noted that Senate President Pro Tem Phil Berger recommended that the spill be discussed in the General Assembly's next meeting in a press release issued four days after the spill, and that the first version of CAMA directly referenced the spill in its preamble. Tr. Vol. 26, p. 745.

Witness Junis also disagreed with Witness Wright's assertion that the Commission should treat DEC the same as it treated DNCP in its 2016 rate case, in which the Commission approved amortization with a return for DNCP's past deferred coal ash costs. Tr. Vol. 26, p. 747. Witness Junis stated that the volume of environmental regulatory action against Dominion was miniscule compared to that against DEC, and that this was borne out by the Company's own responses to Public Staff Data requests in which it failed to produce evidence of environmental violations by DNCP after 1993. Tr. Vol. 26, p. 748.

In supplemental testimony, witness Junis recommended disallowance of an additional $206,553 in expenditures for groundwater extraction and treatment at DEC's Belews Creek plant listed in DEC witness McManeus' second supplemental testimony, which updated coal ash costs through December 31, 2017. Tr. Vol. 26, pp. 752-53. This recommendation is based on the same grounds for the disallowance of groundwater extraction and treatment costs detailed in witness Junis' direct testimony.

In his initially filed and supplemental direct testimony, Public Staff witness Maness identified the following seven adjustments to the Company's proposed recovery of coal ash costs. Some of the adjustments incorporate recommendations from other Public Staff witnesses:

a. Witness Maness incorporated adjustments to reflect a prudent and reasonable level of coal ash expenditures as recommended by Public Staff witnesses Moore, Garrett, and Junis. Tr. Vol. 22, pp. 65-66, 147, 153-54.

b. Witness Maness recommended adjusting the N.C. retail jurisdictional allocation factors to (a) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to South Carolina retail operations; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.

c. Witness Maness recommended addition of a return on deferred coal ash expenditures from December 2017 through April 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. Tr. Vol. 22, pp. 69-70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company has calculated the 2018 net-of-tax debt carrying cost using a Federal income tax rate of 35%; witness Maness recommended using the updated 2018 rate of 21%. Tr. Vol. 22, pp. 149-50.

d. Witness Maness recommended calculation of the return on the deferred coal ash costs be made with a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Tr. Vol. 22, p. 70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company had continued to apply compounding at the end of January each year. Witness Maness continued to recommend compounding carrying costs at the beginning of January each year. Tr. Vol 22, p. 149.

e. In conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended amortization of the balance of deferred coal ash expenditures over a 25-year period, rather than the 5-year period proposed by the Company. Tr. Vol. 22, pp. 70-85, 153-54.

f. Also in conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 25-year amortization period, would produce a 49% ratepayers / 51% investors sharing of the burden of deferred coal ash expenditures. Tr. Vol. 22, pp. 70-85, 153-54, 162.

g. Witness Maness recommended removal of the ongoing annual expense amount, or "run rate," proposed by DEC to recover additional coal ash management costs incurred from the date the rates approved in this proceeding become effective through the date rates become effective in DEC's next general rate case.

G. Company Witnesses – Rebuttal

Rebuttal testimony with respect to the reasonableness and prudence of the Company's coal ash basin closure costs was provided by Company witnesses Kerin, Wright, and Wells. Rebuttal testimony with respect to witness Maness' proposed adjustments was provided by witness McManeus. Rebuttal testimony with respect to the Company's entitlement to earn a return on the unamortized balance of coal ash costs, ARO accounting and the "used and useful" concept, was provided by witnesses Wright, McManeus, and Doss. Such testimony is summarized as follows.

1. Kerin

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett, Moore, and Junis, CUCA witness O'Donnell, AGO witness Wittliff, and Sierra Club witness Quarles. As in the DEP proceeding, witness Kerin testified that witnesses Garrett and Moore engaged in a robust analysis and investigation of the costs that DEC incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He also stated that based on a complete review of the applicable facts and real world conditions, he did not believe their suggested disallowances were warranted, and that they again missed or overlooked key facts in several of their recommendations. Tr. Vol. 24, pp. 90-92.

First, he disagreed with witness Moore's conclusion that it was imprudent and unreasonable for DEC to transport CCR material from Dan River to a landfill in Virginia until the on-site CCR landfill could be constructed, and with their recommended disallowance of $59,320,890, which represents the difference between the cost to transport the material off-site and the cost to dispose of it in what he classified as a hypothetical and impractical on-site landfill along the western property boundary. Witness Kerin stated that witness Moore conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. He also stated that, while witness Moore correctly asserted that the moratorium did not prohibit construction of landfills in other areas of the site, specifically near the western property boundary, based on the Company's exploration of off-site and on-site locations for a CCR landfill for the Dan River ash, locating the on-site landfill on the western property boundary was never a feasible option due to multiple factors that witness Moore did not consider. Tr. Vol. 24, pp. 92, 94-105, 131.

Witness Kerin explained that in June 2015, Duke Energy purchased two tracts of land near Dan River (the Hopkins Tracts), which together with the Dan River plant were subject to a City of Eden zoning ordinance that made landfill construction on those properties cost prohibitive. He explained further that, while DEC and the City of Eden entered into an agreement whereby the City amended its zoning ordinance to allow landfill construction on the Dan River property, several limitations were imposed on the location of an on-site landfill. The landfill could only be located on the Dan River Facility premises, not on the Hopkins Tracts. In addition, the on-site landfill needed to be located near the existing basins, and as remote from residential areas as feasible. Witness Kerin noted that the nearest location to the existing basins is within the footprint of the former ash stack, and that this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. He stated that, because witness Moore's proposed location, in contrast, was not closest to existing basins or as remote as feasible from residential areas, the City of Eden would not likely have approved the zoning required to construct the landfill in this location. Witness Kerin stated that, if witness Moore had considered the City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96.

Witness Kerin maintained further that construction of the landfill in witness Moore's proposed location would require complete excavation of a LCID Landfill on the site. He explained that DEQ had allowed Duke Energy to dispose of asbestos in the Dan River LCID Landfill, and stated his opinion that North Carolina regulators would not allow DEC to disturb a covered landfill containing asbestos. This is because, while asbestos that is covered and in a landfill poses little to no risk to environmental health or safety, when uncovered and disturbed through excavation, it becomes friable and will be released into the air, posing an unacceptable risk to workers and, potentially, neighbors. Witness Kerin also testified that, even if the Company were allowed to excavate the LCID Landfill, disposal of the fill material would have posed additional challenges. While witness Moore asserted that the Company could have disposed of the material at the Rockingham County Landfill, witness Kerin stated that it is not clear that that location would have accepted the volume of asbestos—at least 60,000 cubic yards—required to be excavated from the LCID Landfill. Even if Rockingham would accept the asbestos, because it imposes strict double-bagging requirements for asbestos waste, this requirement would prohibit pursuing this alternative from an operational and labor standpoint. Tr. Vol. 24, pp. 97-98.

Witness Kerin stated that DEC also located the on-site landfill so that it does not interfere with existing streams and wetlands on the Dan River Plant premises. He stated that witness Moore's alternative location would in contrast interfere with two streams and two wetlands and impact several others, which would have required the Company to apply for U.S. Army Corps of Engineers (USACE) and DEQ permits to address those impacts. He also stated that, in the Company's experience, it is not likely that USACE would have approved the requisite permits, or would not have done so in time for the Company to meet the closure deadline of August 2019, especially considering that another on-site location – the one chosen by DEC – would have no impacts to streams or wetlands. He contended that witness Moore's proposal neither avoids nor minimizes impacts to jurisdictional waters, and relies solely on cost as support for his location. He asserted that the location that DEC chose for the landfill allowed it to proceed without litigation or delay, and will allow it to meet its CAMA imposed excavation deadlines. Tr. Vol. 24, pp. 98-100.

Witness Kerin maintained in addition that witness Moore's alternative location did not consider elevation changes and other topographical features, such as the steep slopes on the alternative site that lead to and through streams and wetlands. He also asserted that the steep grading limits the airspace that can be realized for developing a lined landfill of the size needed, and the elevation of witness Moore's proposed location would result in the landfill being in neighbors' line of sight. Witness Kerin also asserted that the land along the western property boundary is not suitable for landfill construction, as the depth to bedrock is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. He asserted further that the slope to stream combination on the western and southern sides of witness Moore's proposed landfill location leaves no area for stormwater management on the low side of the landfill, and that significant borrow resources would be required to fill the toe of the slope to achieve enough buffer from the stream for landfill access and stormwater features, adding expense and time to the project. Further, he maintained that the Company would have needed to obtain a new construction permit and construct an industrial NPDES outfall through the service water pond in order to build witness Moore's proposed landfill, and that both the permit and the outfall would have required substantial time to obtain and construct and would have to be in place before construction on the landfill began. In addition, he maintained that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02.

Finally, with regard to Dan River, witness Kerin maintained that, even if DEC could have overcome all of the obstacles to witness Moore's proposed site, the proposed disallowance was incorrectly calculated. He explained that witness Moore did not correctly calculate the Company's costs for excavating, transporting, and disposing of Ash Stack 1 off-site, and that his proposed $83,531,985 disallowed should be reduced by approximately $3.8 million that is actually attributable to excavation and transportation of ash from the Primary Ash Basin. Witness Kerin also asserted that witness Moore's cost estimates to construct his alternative landfill are too low. He explains that when the presence of asbestos and the need to relocate the warehouse building in the center of the alternative location are accounted for, the cost to build witness Moore's alternative location landfill jumps by $10,790,900 to $35,001,095, thereby reducing witness Moore's proposed disallowance further, to $44,742,265. Witness Kerin emphasized that, because witness Moore's proposed site was not a viable option and never considered by the Company for the myriad reasons he discussed, this recalculation is hypothetical, but that it shows that witness Moore's proposed disallowance is incorrect even if his suggested course of action were possible, which it was not. Tr. Vol. 24, pp. 103-05.

Witness Kerin also disagreed with witness Moore's contention that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and with the recommendation that $10,612,592 associated with beneficiation costs at Buck be disallowed. N.C. Gen. Stat. § 130A-309-216 requires an impoundment owner to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites. Witness Kerin maintained that in keeping with the timing requirements imposed by CAMA, Duke Energy identified Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. While he agreed that reuse of ash at Weatherspoon is appropriate, and noted that the Company is selling Weatherspoon ash for reuse today, he disagreed that Weatherspoon was a possible choice for one of the three beneficiation sites required by CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

Witness Kerin explained that witness Moore mixes apples and oranges by contending that by selecting Buck as a beneficiation site and therefore supplying an additional 300,000 tons per year of CCR material to the concrete industry, the Company in turn reduced demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. He explained that Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, while beneficiated ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Tr. Vol. 24, pp. 105-06.

Witness Kerin maintained further that witness Moore's assertion that choosing Buck increased closure costs at that site compared to other closure options misses several key facts that support the decision to select Buck as the third beneficiation site. He noted that Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, and that the Company reasonably considered the amount of ash available at the site, and the potential uses for the ash when making decision to invest in beneficiation at a particular location. Witness Kerin also maintained that Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. He explained that since trucking the ash is part of the cost of the sales, with its proximity to Charlotte and Greensboro, Buck is in a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia). Witness Kerin noted further that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons to qualify the site for beneficiation. He also asserted that the statute's specific references to installation and operation of an ash beneficiation project and production indicates the General Assembly's intent that Duke Energy construct and operate technology such as carbon burn-out plants and STAR technology, rather than use the basic drying and screening operations occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07.

Witness Kerin also disputed witness Moore's recommendation that the Commission disallow recovery of $2,000,100 related to DEC's purchase of nine adjacent parcels at Cliffside. He stated that witness Moore's conclusion ignores one of the Commission's and DEC's core policies, which is to encourage and promote harmony between public utilities, their users and the environment. He also noted that the cost of the Cliffside parcels was not included in the costs the Company is seeking to recover in this case, and has never been part of the Company's ARO and as such the recommended disallowance of these costs should not be granted. Tr. Vol. 24, pp. 93, 108.

Witness Kerin also objected to witness Moore's suggestion that the $489,000 in costs to ship ash from Riverbend to Homer, Georgia should be disallowed on the basis that the ash could have been shipped to DEC's Marshall Steam Station. Witness Kerin testified that shipping ash to Homer, Georgia was a reasonable, temporary solution that allowed DEC to begin required ash excavation within the mandatory time frame after Riverbend received its NPDES stormwater permit. He explained that the Company sent Riverbend ash to Marshall once that site became available, but that Marshall was not an available location in May 2015, when the Company began trucking ash from Riverbend pursuant to DEQ directives. Those directives, as contained in an August 13, 2014, letter from DEQ, requested that Duke Energy submit an excavation plan for Riverbend by November 15, 2014, and that it begin removing ash at Riverbend within 60 days of receiving DEQ approvals to do so, which included an NPDES Stormwater Permit. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015, to begin excavating Riverbend ash. He stated that while the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet this deadline, and thus it was imperative that the Company find someone to haul and dispose of the Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015 (as opposed to February 2016, as asserted by witness Moore). DEQ approved Duke Energy's request to dispose Riverbend ash at Marshall on June 19, 2015, which did not allow enough time for the Company to accomplish all of the tasks required to utilize Marshall and still meet the 60-day deadline. Once those tasks were accomplished, DEC did begin transporting Riverbend ash to Marshall on July 22, 2015, seven days after DEQ's excavation deadline. Tr. Vol. 24, pp. 93, 108-10, 131-32.

Witness Kerin also clarified that DEC could not have stopped trucking Riverbend ash to the R&B Landfill once it began trucking to Marshall, as the Company was under contract with Waste Management to dispose of the ash at R&B for 17 weeks, or through September 18, 2015, and would have been in breach of contract if it had halted the ash transport before that date. He also stated that the Company's decision to enter into a 17-week contract was based on several factors, including the short turnaround needed for a contractor to truck and accept the ash, and the knowledge that this would be a temporary disposal site and resulting need to find a contractor willing to accept a limited tonnage of ash. Tr. Vol. 24, pp. 110-11.

Finally, witness Kerin noted that Public Staff witness Garrett agreed with the Company that the Inactive Ash Basin and the Old Ash Fill at W.S. Lee needed to be excavated. Witness Kerin disagreed, however, with witness Garrett's assertion that DEC should have delayed excavation of ash material from the Inactive Ash Basin (IAB) and Old Ash Fill at W.S. Lee in order to undertake a grading and slope stabilization project, excavate the overly steep sections of the IAB berm, and dispose of that ash on-site. Witness Kerin testified that this approach would not have been reasonable or prudent and therefore disagreed with witness Garrett's recommendation that the costs associated with transferring ash to Brickhaven ($27,275,192) should be disallowed. Tr. Vol. 24, pp. 93, 111-12, 132.

Witness Kerin testified that, consistent with a Consent Agreement entered into by Duke Energy and the SCDHEC in September 2014, which required excavation of the IAB, the Company excavated ash from this basin and trucked it to the solid waste landfill operated by Waste Management in Homer, Georgia. He explained that, based on available stability analysis, the IAB did not meet the required CCR Rule dam safety factors for maximum storage pool and liquefaction conditions. He concluded that it was therefore reasonable and prudent for DEC to begin excavation immediately. Witness Kerin also noted that at the time the Company was deciding how to manage the IAB, its priority was to address stability and erosion concerns on the river frontage along the IAB dike. He asserted that, due to the low safety factors of the IAB dike, the Company was already limiting equipment access on the dike crests, which limited work to the very narrow portion of downslope area that extended from the dike toe to the river's edge. Witness Kerin asserted further that the equipment necessary to implement witness Garrett's proposal could not have safety traversed the dike on the downslope, and that moving the heavy equipment to the downstream/river side of the downslope would have created undue risk to bank stability and unnecessarily risked worker safety. In addition, while the Company evaluated interim measures that could offer stability and risk mitigation during excavation, these involved work at and in the river to both access and install the features, and the Company decided not to pursue these measures due to the time needed to obtain a USACE permit for work in the river. He noted that the Company had already initiated the IAB's excavation and that by the anticipated 12-month time period to obtain the permit and 4-6 months to install the required features, the basin would be nearly excavated, and the Company would have to later remove the features to restore the river. Witness Kerin maintained that witness Garrett's proposed two-phased approach would not address these issues, would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. Tr. Vol. 24, pp. 112-14, 132.

Witness Kerin disagreed with witness Garrett that the Company should have agreed to different terms in the Consent Agreement with SCDHEC. He explained that, based on SCDHEC's expressed concerns, the deadlines agreed to pursuant to the Consent Agreement were reasonable and allowed the Company to achieve the primary goal of the agreement, which was to excavate ash. SCDHEC's concerns were driven by the IAB abutting the Saluda River and the resulting risk of river impacts, the steepness of the banks, and the heavily wooded nature of the slope. He stated that SCDHEC wanted Duke Energy to take prompt action with respect to excavating the IAB, and that desire is reflected in the Consent Agreement and excavation deadlines. Tr. Vol. 24, p. 115.

Witness Kerin also disagreed with witness Garrett that the Company should have delayed excavation of the Old Ash Fill, noting that the Old Ash Fill was also subject to the Consent Agreement and that the SCDHEC was as adamant that the Company excavate this site immediately as it was with regard to the IAB. Tr. Vol. 24, p. 116.

Finally, witness Kerin testified in response to witness Garrett's criticism of DEC's plan to excavate the Structural Fill Area at W.S. Lee in the future, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate the future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

Witness Kerin also testified that Public Staff witness Junis' testimony, similar to witness Lucas in the DEP case, incorrectly asserts that the costs of groundwater treatment wells installed at Belews Creek would not have been incurred absent the Sutton Settlement. Witness Kerin asserted that this conclusion ignores the fact that, while the measures undertaken at Belews Creek were reflected in the Sutton Settlement, they were moved up in time from when they would have otherwise been required, and DEC would have installed extraction wells in order to comply with CAMA even without the Sutton Settlement. Tr. Vol. 24, p. 117.

He also disagreed with witness Junis' contention that the Company should not recover the cost of equipment that could remove selenium at Riverbend. He stated that witness Junis' recommendation does not reflect the reality of managing that facility either at the time of that purchase or at present. He explained that in order to excavate the Riverbend ash, as required by CAMA, DEC had to dewater the impoundments, and that the interstitial water treatment system for the dewatering process was designed to meet NPDES permit limits, including selenium. The environmental consultant hired by the Company to develop this treatment system, WesTech, proposed the SeaHAWK bioreactor system for this purpose. Witness Kerin contended that it was imperative for the Company to have a treatment system that could appropriately treat the site's wastewater and meet future permit selenium limits. He stated that, while the SeaHAWK is important to the Company for staying within its permit limits, it is expensive to operate (approximately $60,000/month), and that the Company will only use it when other physical and chemical extraction methods are insufficient. Witness Kerin emphasized, however, the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations in the case that selenium levels increased and the bioreactor was not on site. He offered the example of a five-month delay to secure a bioreactor would cost the Company several million dollars in delay charges under its contract with Charah. He concluded that it was reasonable and prudent for DEC to purchase a bioreactor system to mitigate against potential violations of NPDES permit limits and to treat decanted wastewater at Riverbend, and that the recommended disallowance of those costs should therefore be rejected. Tr. Vol. 24, pp. 90, 117-19, 132.

Witness Kerin also rebutted AGO witness Wittliff's assertion that the Commission should disallow the Company's coal ash costs, and noted that witness Wittliff's testimony appears to go even further in this case than his recommended disallowance in the DEP case. Witness Kerin testified that witness Wittliff's testimony, with its revisionist history approach to coal ash management and his inability to specify or quantify specific disallowances, is not useful to the Commission. Tr. Vol. 24, pp. 91, 133.

Witness Kerin testified that AGO witness Wittliff's contentions that DEC's management of coal ash has lagged behind the rest of the utility industry, and that the Company has ignored dam safety at its facilities, are incorrect. He asserted that DEC's ash management practices have conformed and evolved with changes in industry practices and regulatory standards. He noted that witness Wittliff based his assertion that the Company knew by 2008 that impoundments were no longer the industry standard in part on excerpts from Duke Energy's 10-K filings around that time. He stated that these excerpts, which pertain to Duke Energy and not to individual utilities like DEC, simply notify the Securities and Exchange Commission of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject, but were not intended to analyze DEC's coal ash management practices and do not support witness Wittliff's claim that the Company's coal ash management practices were out of step with industry or that the Company knew of any such inconsistency. Witness Kerin also stated that while the 1988 and 1999 EPA Reports cited by witness Wittliff in support of his position show increases in the percentages of new lined landfills and surface impoundments, witness Wittliff acknowledged that the Company last constructed a new ash basin in 1982. In addition, while these reports show an increase in the percentage of basins that were lined from 17 to 28% between 1975 and 1995, 28% is still a minority of new basins being constructed, which is consistent with DEC's practice during this time frame. Witness Kerin stated further that witness Wittliff's assertion fails to account for site-specific conditions, which as the EPA explains in the preamble to the CCR Rule and guidance, is an essential consideration when making CCR unit-specific determinations. Finally, he pointed out that witness Wittliff presented no credible evidence to show that the Company's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time. Tr. Vol. 24, pp. 119-21.

Witness Kerin also rebutted witness Wittliff's assertion that DEC should have built new lined impoundments as opposed to expanding existing unlined impoundments. He testified that witness Wittliff's argument ignores the fact that construction of new lined impoundments would have entailed significant expense to the Company, while not removing the need to maintain existing unlined impoundments. In addition, because such action would have occurred before it was consistent with industry standards, it would have put the Company at risk of disallowance of those costs. Witness Kerin stated that the suggestion that DEC chose not to construct new lined impoundments in order to delay and avoid potential exposure to requirements for more rigorous environmental standards is therefore not only unfounded but also inconsistent with the realities of managing coal ash basins. He noted that, at the hearing in the DEP proceeding, witness Wittliff admitted that the majority of utilities in the country continued to use unlined, wet ash impoundments well after the timeframe in which he alleges the Company should have ceased to do so, because the law allowed them to do it, and the law continued to allow them to do it. Witness Kerin noted the inconsistency between admitting that the Company's use of unlined, wet basins was legal and in line with most utilities in this country, and asserting that DEC was imprudent by doing so. Tr. Vol. 24, pp. 121-22.

Witness Kerin also responded to witness Wittliff's contention that dam safety has not been a priority for the Company, and stated that DEC has a very robust dam safety program, led by a central organization with responsibilities for each site in the system. The program includes weekly documented inspections, and tracking of any corrective actions, as well as episodic inspections to be conducted following heavy rain events or certain seismic events. He stated that the Company also conducts detailed, documented annual inspections of each facility, and that any issues identified are tracked through to resolution. He noted in addition that the Company internally inspects and documents basin discharge piping annually, and again tracks identified issues through to resolution. Any required modifications are managed through a stringent program including plans and specifications submitted to and approved by DEQ's Dam Safety Program. This is all in addition to DEQ's own annual inspections of the basins and all completed modification projects. He stated that the Company provided five-year dam safety inspections dating to the 1970s. He maintained that no instance arose in which the Company failed to act upon a major dam safety issue. He argued that subsequent mentions of certain issues simply show that DEC was monitoring the condition before identifying or confirming the need for longer- term repair, and that these inspections do not show any major issue that threatened the integrity of the dam's ability to retain the ash in the basin. Tr. Vol. 24, pp. 122-24.

Witness Kerin responded to witness Wittliff's criticism of witness Kerin's own CCR experience and qualifications to discuss ash management industry standards, noting the irony of witness Wittliff's position in light of his own limited experience in this area. Tr. Vol. 24, p. 124.

Witness Kerin also testified that, like his testimony in the DEP case, CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion, and that witness O'Donnell made little effort to address those flaws in his conclusions from the earlier case. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that his national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%. He stated that witness O'Donnell appears not to have considered 23 factors that must be accounted for in order to seriously attempt this type of analysis. He also stated that witness O'Donnell made no attempt to quantify DEC's coal ash AROs resulting from CAMA, as compared to its obligations under the CCR Rule, or to determine the impetus for coal ash AROs for the other utilities to which he compares the Company. Witness Kerin argued that witness O'Donnell cannot credibly testify that the Company's ARO coal ash costs are higher because of CAMA when he cannot attribute any specific ARO coal ash costs to CAMA or attribute ARO coal ash costs for other companies to any particular regulatory obligation. He explained that, even if witness O'Donnell had conducted such an analysis, it would not provide an accurate comparison, because other utilities are in very different stages of their coal ash management timeline than DEC. Witness Kerin also maintained that the SNL data relied upon by witness O'Donnell are rough estimates, and that there is substantial uncertainty over the level of actual closure costs for many of those utilities he listed. Witness Kerin therefore recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. Tr. Vol. 24, pp. 90, 125-28, 133.

Finally, witness Kerin disagreed with Sierra Club witness Quarles' assertions as to the consistency of DEC's coal ash management practices with industry, the costs of lined landfills as compared to surface impoundments, and Duke Energy's previous pursuits of reuse options for ash. Tr. Vol. 24, p. 91. For the same reasons he presented in response to witness Wittliff's testimony, witness Kerin disagreed with witness Quarles' conclusion that operation of unlined basins after the 1980s was unreasonable, and countered that witness Quarles does not appear to have considered industry standards or regulatory requirements or, like witness Wittliff, to have presented any specific evidence that the Company's impoundment engineering and design was not consistent with industry practice and regulatory requirements at the time. He also testified that witness Quarles' assertion that closure costs for surface impoundments were higher than costs for lined landfills fails to consider the additional costs associated with conversion to lined landfills, in addition to the fact that DEC last constructed a new basin in 1982. Finally, witness Kerin clarified that the Company did make sales of coal ash for reuse during the 1980s, from Marshall in 1986 and Belews Creek in 1988, contrary to witness Quarles' assertion otherwise. Tr. Vol. 24, pp. 128-29, 133-34.

2. Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Garrett, Moore, Junis, and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not provide a proper basis on which costs may be disallowed, and should be rejected by the Commission. Tr. Vol. 12, pp. 156-2-3, 161-62.

Witness Wright first disagreed with Public Staff witness Junis' recommendation to disallow approximately 49% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Junis did not find the Company imprudent for most of the coal ash-related cost, nor did witness Junis find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Junis asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues. Witness Wright maintained that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. Tr. Vol. 12, pp. 156-4, 162-63.

Witness Wright also explained that the proposed sharing of cost is inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that the Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEC. Tr. Vol. 12, pp. 156-12, 163.

Witness Wright also testified that the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. He stated that this is consistent with the recent Dominion case, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property. Tr. Vol. 12, p. 156-16 – 156-19.

Witness Wright proceeded to state that the Commission's treatment of environmental cleanup of manufactured natural gas (MNG) plants also does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. Tr. Vol. 12, p. 156-18.

Witness Wright also testified that the 25-year amortization period proposed by the Public Staff is not justified by their cost sharing theory, which is based on a culpability theory and by defining these costs as being extremely large. He explained that adoption of this proposal would undermine the basic cost of recovery principles embodied in the North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. He explained further that it could also result in a perception of the State's utilities as riskier, leading to higher cost of capital and cost of service. Tr. Vol. 12, p. 156-22.

Witness Wright disagreed with witnesses who claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. Tr. Vol. 12, pp. 156-24 – 156-27, 163-64.

Witness Wright also argued that CAMA was not intended to be a punitive law. He stressed that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy. Tr. Vol. 12, pp. 156-28 – 156-31, 164-65.

With regard to coal ash litigation costs, witness Wright reiterated that DEC has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. Tr. Vol. 12, p. 156. He also opined, however, that witness Junis' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. Tr. Vol. 12, pp. 156-31 – 156-36, 165.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. Tr. Vol. 12, pp. 156-39 – 156-40, 165.

Additionally, witness Wright disagreed with Junis' recommendation that costs to remedy environmental violations where the costs exceed what CAMA would have required be disallowed, including those specifically related to Belews Creek groundwater extraction and treatment and a second related Riverbend selenium removal. Witness Wright, citing to his earlier testimony, stated first, that absent a finding that the Company was guilty or had liability associated with environmental issues that led to additional compliance costs, or that the settlement in question Junis was citing to was imprudent, that environmental costs like the Belews Creek costs noted here should be recovered from ratepayers and not shareholders. Secondly, in regard to Junis' statements that DEC had a duty to comply with groundwater rules, and its failure to comply are a reason to deny the recovery of these costs with or without settlement, witness Wright cited his earlier testimony where he discusses how and why unlined coal ash pond exceedances occur and are not unexpected. Moreover, witness Wright noted his earlier testimony in explaining why witness Junis' theory that DEC had a duty to comply with the North Carolina groundwater rules, Title 15A, Subchapter 2L of the North Carolina Administrative Code (2L rules), without regard to whether it followed accepted industry practices, is misplaced. Tr. Vol. 12, pp. 156-36 – 156-38, 162.

Next, witness Wright stated that he disagreed with CUCA witness O'Donnell's belief that the DEC was responsible for the passage of CAMA and should be responsible for any coal ash costs above that required by the CCR Rule, and cited to his earlier statements disagreeing with such. Witness Wright opined that the Commission should reject witness O'Donnell's recommendation that the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that witness O'Donnell's analysis neither considered the fact that most utilities are behind DEC from a timing perspective in both planning and addressing coal ash pond closure, nor reflected the most recent coal ash CCR costs being reported by various electric utilities. Witness Wright also disagreed with witness O'Donnell's statement that the EPA's reconsideration of aspects of its CCR Rule "direct[ly] conflict[s]" with witness Wright's statements about this country's ever-tightening environmental standards. Witness Wright stated that although it was possible that the EPA could modify its current rule, there is no way for DEC to know if, when, or how such modification might occur. Tr. Vol. 12, p. 156-40 – 156-43.

Finally, witness Wright testified that the Commission should reject AGO witness Wittliff's recommendation that because the Company had a "history" of regulatory violations, and due to the Dan River accident leading to the enactment of CAMA, DEC should be disallowed recovery of coal ash related costs. In reference to his earlier statements on CAMA and his direct testimony, witness Wright reiterated his belief that the North Carolina legislature would have adopted some type of state specific coal ash closure legislation shortly after the passage of CCR, regardless of the Dan River accident. He noted that witness Wittliff did not quantify the disallowance he recommends, but instead assumed that the costs incurred to comply with both the Federal CCR rules and CAMA were unreasonable or imprudent without any underlying support. Additionally, witness Wright identified that witness Wittliff's recommended disallowance was also at odds with his testimony filed in the DEP case. Tr. Vol. 12, pp. 156-43 – 156-44, 163-64.

At the hearing, witness Wright explained in response to questions by counsel for the Sierra Club that, if the Commission approved the Company's request for recovery of ongoing expenses, the Company would then bring its actual costs to the Commission for review and approval annually. Tr. Vol. 12, p. 186. Witness Wright also explained in response to questions regarding EPRI documents from the 1980s that those reports acknowledged that more information was being provided about potential impacts from coal ash, but that the reports also advised that disposal procedures not yet be modified. Id. at 191-92. During cross by counsel for NC WARN, he discussed the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. Witness Wright explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers and, if so, the next question is whether they were used and useful and, if so, the last stage is to consider what outcome would be fair and equitable. Witness Wright explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. Id. at 202-06.

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEC has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEC is seeking in this case. Witness Wright explained that if DEC has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, those costs or fines should not be recovered. Witness Wright testified that that is different from DEC having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. Tr. Vol. 13, pp. 77-78, 91-93. On redirect, witness Wright agreed that it is reasonable to assume that state and federal regulators who understood how soil and water interact with each other would have passed appropriate rules and regulations over time to account for that interaction. Tr. Vol. 13, pp. 95-96.

In response to questions by the Chairman, witness Wright confirmed that, in his opinion, the Commission's primary responsibility pertains to cost recovery rather than regulating how utilities implement state and federal environmental laws, and agreed that DEQ was the agency in charge of approving coal ash remediation plans. Witness Wright also agreed that the Commission is not a court of general jurisdiction, and that it determines the reasonableness and prudence of utility decisions rather than make cost recovery decisions by following a duty of care or any other standard available in tort or other type of law. Witness Wright confirmed that this standard does not consider what could or should be anticipated into the future, but considers what is reasonable and prudent given the information known now. Tr. Vol. 13, pp. 99-102.

3. Wells

Company witness Wells testified on rebuttal to the different approach taken by the Public Staff in this case from the DEP case. In the DEP case, the Public Staff attempted to characterize DEP's compliance with its NPDES permits as poor. In this case, witness Junis did not discuss DEC's compliance with NPDES permit requirements, which witness Wells noted has been outstanding, but rather suggested that the existence of seepage at the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

Witness Wells testified that Public Staff witness Junis' negative characterization of DEC's compliance record is not justified by the historical record. Tr. Vol. 24, p. 224. He explained that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. Witness Wells stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. Witness Wells testified that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built. Witness Wells noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. Witness Wells noted further that as requirements changed over time, DEC has taken every action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. Tr. Vol. 24, pp. 227-29, 236, 258.

Witness Wells opposed the suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, contrary to witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells disagreed with witness Junis' apparent contention that DEC should have moved well ahead of accepted science, regulatory requirements, and industry practice and begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He explained that the papers cited by witnesses Junis, Wittliff, and Quarles discussing potential issues associated with coal ash disposal, and the importance of developing and implementing appropriate controls, highlight the evolving state of knowledge regarding the risks and best practices related to coal ash disposal management, rather than condemn the use of unlined basins. Tr. Vol. 24, pp. 232-34, 258-59.

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Junis contends, to be punitive. While he agreed that the groundwater rules require corrective action without regard to fault, he disagreed with witness Junis' conclusion that responsibility for corrective action is equivalent to any other violation of the law. He stated that the record in this case clearly demonstrates that groundwater contamination resulted from DEC's otherwise lawful use of unlined ash basins in furtherance of its mission to provide low cost electricity, and that the use of ash basins was an accepted and reasonable practice conducted with DEQ and EPA oversight. He explained that, for historical sites such as those at issue in this case, this State's groundwater regulations and the DEQ's practices and policies, as well as the CCR Rule, are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health or safety, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He concluded that, if the utility cooperates with DEQ, the applicable law and policies are designed to drive corrective action rather than enforcement action, and he saw no intent for those law and policies to be used to deny cost recovery in regulatory proceedings. Tr. Vol. 24, pp. 237-38, 260.

Witness Wells also stated that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that measurement does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." He stated that it would be more accurate to say that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-40, 260-61.

Witness Wells also explained that the extraction and treatment activity required by the Sutton Settlement, which costs witness Junis recommends for disallowance, is work that the Company simply agreed to perform earlier than required under the CCR Rule and CAMA in order to address offsite groundwater impacts. Tr. Vol. 24, pp. 241, 260.

Witness Wells also disagreed with witness Junis that the amount of litigation regarding the Company's ash basins suggests that the Company was imprudent in managing ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of ash from all basins across the Southeast. He stated that DEC has appropriately been opposed to this, arguing instead that final closure methods should be dictated by the CAMA process and a site-specific balancing of net environmental benefits of various closure options based on science, regulatory policy, and the best interest of the Company's customers. He stated that the positions of the NGOs and the suits do not themselves indicate imprudence. Rather, he explained, the appropriate closure methodology must take into consideration the particular characteristics of each site. He stated that the EPA and North Carolina agree and that, consistent with this principle DEC has settled cases where science and engineering supported closure by excavation, and continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. He concluded that the volume of filed litigation on its own should not factor into the Commission's determination of whether the Company's CCR costs were prudently incurred. Tr. Vol. 24, pp. 242-44.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. He reiterated that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules. He also stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to a notice of violation (NOV) and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to corrective action is conducted. He testified that the 2L Rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 244-46.

Witness Wells also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He asserted that DEQ did not consider seeps to have a significant environmental impact. He also maintained that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He maintained that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He asserted that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. Tr. Vol. 24, pp. 246-50, 261.

Accordingly, Witness Wells explained, DEC entered into a special order by consent (SOC) with DEQ to address seeps at the Allen, Marshall, and Rogers (formerly Cliffside) stations. He explained that the SOC provides regulatory clarity and certainty as to the appropriate monitoring frequency, parameters to be sampled and limits with respect to the non-engineered seeps, while requiring the Company to accelerate the schedule for decanting water from the basins, a process that is expected to substantially reduce or eliminate seeps. He further testified that DEC is working with DEQ to develop additional SOCs based on this model to address non-engineered seeps at the remainder of DEC's and DEP's impoundments. He clarified that the SOC requirements to accelerate decanting do not create additional costs for the Company over and above the cost to complete these activities in compliance with CAMA and the CCR Rule. In sum, witness Wells testified that the application for and execution of SOCs to address seeps is not evidence of DEC "culpability," but rather a regulatory mechanism to provide clarity and alignment with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. Tr. Vol. 24, pp. 251-53, 261.

Finally, witness Wells disagreed with witness Junis' suggestion that DEC caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash, but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. Tr. Vol. 24, pp. 254-55, 261-62.

At the hearing, in responding to questions by counsel for the Sierra Club, witness Wells responded that the Company did engage in voluntary analysis of its coal ash sites prior to DEQ requirements to do so, as far back as the 1970s at Allen, and determined based on those analyses that no significant impacts to groundwater were occurring, and no significant risk to groundwater going forward. Tr. Vol. 25, pp. 36-37.

In response to questions by the Commission, witness Wells confirmed that while the AGO and Public Staff presented documents in this case addressing the Company's actions going back to the 1950s, the AGO took no action itself with regard to coal ash management until 2014, when the AGO became involved with citizen suits. He opined that the reason for that inaction was that the Company's actions with regard to coal ash were acceptable from a regulatory perspective until much more recently. Tr. Vol. 26, pp. 72-73. He also stated that DEC's recent comprehensive studies of the groundwater surrounding the Company's ash basins conducted pursuant to CAMA have confirmed that, while groundwater has been impacted, there is no evidence of any current or likely future impacts to, for example, off-site drinking wells or other receptors at any of the seven sites, and have validated the Company's measured approach to coal ash management in previous years. Id. at 77-80. He confirmed that the Company currently has installed wastewater treatment equipment where needed at all of its basins to comply with CAMA. Id. at 82-83.

In response to questions by the Chairman, he further confirmed that, absent other considerations, there are a number of remedies to address a seep that could be applied rather than to excavate the basin. Tr. Vol. 26, pp. 85-88. He also stated that substances such as iron, manganese, and pH are classified by the EPA as secondary maximum contaminant levels which are regulated based on aesthetics (e.g., taste, odor, etc.) and are not considered health risks. Witness Wells acknowledged that some recent studies have suggested that exposure to extremely high levels of manganese could pose a health risk, but explained that, typically, those levels are orders of magnitude above where the limit was set for aesthetic purposes. Id. at 88-91. Finally, he addressed the difficulty of monitoring groundwater impacts, especially when dealing with naturally occurring elements, and explained that a single monitoring well is a snapshot of that particular area at that point in time, and that conditions 100 yards away could be very different, yet still be naturally occurring. He stated that this is why the Company's efforts to monitor a large area is an iterative process. Id. at 91-93.

4. McManeus

On rebuttal, witness McManeus responded to witness Maness' proposed adjustments regarding coal ash pond closure costs. She explained that there were two main adjustments, to remove ongoing environmental costs and adjust deferred environmental costs, as listed in Boswell Exhibit 1, Schedule 1, and based upon seven specific adjustments proposed by witness Maness. Witness McManeus explained that although the Company disagrees with the majority of the Public Staff's seven proposed adjustments, it does not disagree with witness Maness' third or fourth adjustments. Witness Maness' third adjustment is to add a return on the deferred balance up through the expected date of new rates in this proceeding. The fourth adjustment is to calculate the return using a mid-month convention rather than a beginning-of-month convention. Tr. Vol. 6, pp. 312-14, 357-58.

In regard to witness Maness' second adjustment recommending that the costs DEC has identified as "CAMA only" be allocated based on an allocator that allocates to all jurisdictions, witness McManeus explained that the Company has identified very specific cost categories that should be treated as an exception to the general allocation rule that costs of a system be borne by all of the users of the system. Witness McManeus explained that these costs are unique to North Carolina and that such an exception is consistent with other examples where the Commission has allowed direct assignment to North Carolina, and cited to the cost allocation methods used in regard to the North Carolina Renewable Energy and Energy Efficiency Standard and the Clean Smokestacks Act. Witness McManeus further explained that the Company disagreed with witness

Maness' first, fifth, sixth, and seventh proposed adjustments, and that such adjustments were addressed by other Company witnesses' testimony. Tr. Vol. 6, pp. 312-16, 357-58.

Witness McManeus rebutted the Public Staff's recommendation to exclude the deferred coal ash balance from rate base, and indicated that, to the contrary, it was appropriate for that balance to remain in rate base and for the Company to earn a return on it. She indicated that while witness Doss approached this issue from an accounting perspective, from her viewpoint it was important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes, including construction of electric plant, but, she stated, there are other purposes as well – for example, to purchase fuel inventory or to provide cash working capital, etc. Tr. Vol. 6, p. 317. In this particular case, she indicated, investors have advanced funds to pay for coal ash compliance costs, and it is therefore appropriate for the Company to be allowed a return on the deferred coal ash balance during the period for which the Company will amortize and collect these amounts from its customers, as the Company will continue to incur financing costs on the balance of funds that is uncollected. Id. She added that the characteristic that makes the deferred coal ash cost a legitimate component of rate base is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

Lastly, witness McManeus addressed witness Maness' statement that expenses of operating and maintaining property in rate base in the present or in the future "are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses." Agreeing with his statement, she explained that this is the principle underlying the Company's proposal for recovery of the ongoing annual coal ash basin closure costs, what witness Maness terms the "run rate." Witness McManeus stated that these ongoing compliance costs are no different from other ongoing and recurring expenses the Company incurs in the test year, and that such costs are equivalent to the Company's reasonable and prudent test year coal ash basin closure spend. She further explained how the Company's proposed recovery of these ongoing compliance costs through rates would be subject to true-up in subsequent rate cases so that only actual costs are recovered. In conclusion, witness McManeus cited to Chairman Finley's statements in the recent DEP rate case proceeding that a rider could be an alternative mechanism for cost recovery of on-going compliance costs, and stated that the Company agrees that a rider would be an appropriate alternative mechanism to recover such costs. Tr. Vol. 6, pp. 315-16, 357-58.

5. Doss

Witness Doss rebutted the Public Staff's positions regarding ARO accounting that the Company employed for its deferred coal ash compliance costs, and, in particular, witness Maness' characterization of those costs as a deferred expense. Witness Doss provided a detailed explanation of the GAAP and FERC accounting rules with respect to the ARO established in connection with the Company's coal ash basin closure obligations, as well as the deferral orders issued by the Commission in Docket No. E-7, Sub 723. Tr. Vol 12, pp. 61-71. He noted that the Company had simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts, and had deferred the impacts of ARO accounting, as authorized by the Commission's deferral orders. Id. at 70-71.

Witness Doss also responded to witness Maness' opinion that coal ash costs should not be classified as "used and useful" costs. He indicated that, to the contrary, under GAAP and FERC accounting guidance, the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired. Id. at 71. He noted further that such costs are used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity, and that the achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. Id. at 73.

Commission Determinations

General Cost Recovery Principles

A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it in the opening paragraphs to a chapter (titled "The Role of the Revenue Requirement") in their treatise on utility regulation:

> No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….
>
> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

Jonathan A. Lesser & Leonardo R. Giacchino, Fundamentals of Utility Regulation 39 (Pub. Utils. Reports, Inc., ed., 2007) (Lesser & Giacchino).

Lesser & Giacchino refers to the concept of cost recovery as the "revenue requirement" (id.), and the North Carolina Supreme Court has also acknowledged its central role in utility ratemaking. See, e.g., State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (Thornburg II) and State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (Thornburg I), in which the concept is stated to be embedded in the statutory rate making formula, and, indeed, expressed formulaically:

> This statute [N.C. Gen. Stat. § 62-133] requires the Commission to determine the utility's rate base (RB), its reasonable operating expenses (OE), and a fair rate of return on the company's capital investment (RR). These three components are then combined according to a formula which can be expressed as follows:
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> (RB x RR) + OE = REVENUE REQUIREMENT

Costs are not recoverable simply because they are incurred by the utility. The utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) where included in rate base "used and useful" in the provision of service to customers. Lesser & Giacchino, at 41-43. But once it has shown that these metrics are met, the utility should have the opportunity to recover the costs so incurred. This is what North Carolina's ratemaking statute requires (see N.C. Gen. Stat. § 62-133(b)(5)), and to do otherwise would amount to an unconstitutional taking.

In this case, no party has questioned whether the coal ash basin closure costs for which the Company seeks recovery are "known and measurable"; indeed, the Company documented these costs and has shown that they were in fact incurred. Rather, the arguments raised by Intervenors challenging the inclusion of the Company's coal ash basin closure costs in rates center on whether those costs are "reasonable and prudent" and whether they are "used and useful." These concepts have been framed by this Commission and the North Carolina Supreme Court.

A. Reasonable and Prudent

The seminal treatment of "reasonable and prudent" costs is this Commission's order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved with some exceptions costs the Company incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. See 1988 DEP Rate Order. The Commission there articulated the following principles governing the question of "reasonable and prudent":

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard … must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted." 1988 DEP Rate Order, p. 14.

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2)

demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Specifically,

- A decision cannot be imprudent if it represents the only feasible way to accomplish a necessary goal.
- The Commission can only disallow imprudent expenditures – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. Thus, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact.
- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management.

Id. at 15. The North Carolina Supreme Court upheld the Commission's prudence determination. See Thornburg II, 325 N.C. at 489, 385 S.E.2d at 466 (finding "no error" in that portion of the Commission's decision).

B. Used and Useful

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. Gen. Stat. § 62-133(b)(1) states that the Commission must "Ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense …." In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserting as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, see Thornburg II, 325 N.C. at 495-96, 385 S.E.2d at 469, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1). State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc., 335 N.C. 493, 508, 439 S.E.2d 127, 135 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

C. Burden of Proof

The Commission must address arguments on the burden of proof. DEC argues that it incurred the CCR remediation costs at issue, meeting its prima facie burden and that Intervenors have failed to justify discrete disallowances. The AGO argues DEC bore the burden of quantifying the disallowances the AGO deems appropriate. DEC argues that the substantive standard is imprudence. Others argue that the standard is one of due care. The CCR remediation costs DEC seeks to recover in this docket and that are being challenged by Intervenors consist of 2015-2017 costs to dewater, remove, and transport CCRs from unlined repositories and store them in lined ones or to install caps. DEC incurs these costs pursuant to requirements of EPA CCR Rule and North Carolina CAMA provisions or other requirements of DEQ. In compliance with this Commission's authorization, these costs have been accounted for in an Asset Retirement Obligation account and have been deferred to permit appropriate ratemaking treatment in this case.

The AGO argues that DEC should bear the burden to disprove why disallowances to its 2015-2017 CCR remediation costs should not be accepted.

> The AGO does not agree that the factors the Commission found appropriate for an approach taken by an independent auditor in the 1988 DEP Order should have been applied in the 2018 DEP Rate Order as a prudence framework, and similarly in this general rate case, the prudence framework is inappropriate because it essentially puts the burden of proof on intervenors, contrary to settled law. As the Commission observed in the 2018 DEP Order, because costs are site-specific, establishing a past cost would be a "near impossibility." 2018 DEP Order p. 200. As discussed in detail in Part I.B below, there is extensive affirmative evidence that Duke's imprudent management of coal ash disposal and coal ash sites, and its delays in addressing known problems, have driven up the costs now being incurred and have shifted the costs onto future customers unfairly. It is not appropriate to require ratepayers to prove that costs are unrecoverable; rather it is up to Duke to prove that some or all of the detailed costs are not attributable to the poor history of operations; that prudent alternatives that would have reduced the costs were not available when problems became known; and that these factors support the reasonableness of the costs Duke seeks to recover.

AGO's Brief, pp. 9-10.

The AGO cites no authority for this argument, nor does it argue that cases and precedent relied upon by DEC and the Commission in the 2018 DEP case to the contrary are wrongly decided or should be ignored. While asserting that the Commission's reliance on established evidentiary principles in the 2018 DEP case is "contrary to law," the AGO cites no authority to back up its assertion. The AGO asserts in response to DEC's petition to recover 2015-2017 CCR remediation costs -- costs no party asserts DEC did not incur -- that these costs should be disallowed due to DEC's imprudence in years prior to 2015. These are the AGO's allegations, not DEC's. The AGO's novel theory that a petitioner should bear the burden to disprove Intervenor allegations unsupported by evidence is one the Commission does not accept. The AGO's theory of its case, at least in its brief, appears to be that if DEC had acted to remediate CCR disposal and storage issues in years prior to 2015, DEC's costs would have been lower, so the 2015-2017 costs are excessive. To prevail, the AGO must quantify what the costs of the actions not taken should have been. The AGO argues DEC failed to act appropriately before 2015. DEC cannot be expected to provide costs of acts not taken. The AGO has not undertaken this task.

While some of the costs to comply with the requirements of environmental regulators are challenged by Intervenors as excessive, i.e., unreasonable, most of the costs being challenged are questioned on the theory that DEC is in breach of a standard classified as a "duty to exercise due care." The challenge equates failure to meet a due care standard with management imprudence. According to this theory, even though no environmental regulatory requirement imposed a duty to remove CCRs from unlined impoundments before EPA CCR rules or CAMA, management was imprudent in not doing so. The challenge does not address DEC's decisions to initially place the CCRs in unlined impoundments between 1945 and 1982, but its failure to remove the CCRs thereafter or alternatively to cease to sluice CCRs to these unlined impoundments at a time when trends within the industry suggested that leachate finding its way into groundwater from the bottom of the unlined repositories posed potential risks to the environment and human health.

The Commission has not been cited any case to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with express requirements of environmental regulators, management's decisions should be assessed against a standard of due care. The Commission's duty is not to determine liability to and assess damages for torts committed by management for injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify a breach of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issue before this economic regulatory tribunal is imprudence - who should bear the remediation costs - the utility's stockholders or its consumers and on the basis of what justification.

According to the U.S. Supreme Court:

> Good faith is to be presumed on the part of managers of a business. … In the absence of showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.

West Ohio Gas Co. v. Ohio Pub. Utils. Comm'n., 294 U.S. 63, 72, 55 S. Ct. 316, 321 (1935).

In a case cited with favor in Priest, Principles of Public Utility Regulation:[57]

> Only where affirmative evidence is offered challenging the reasonableness of the operating expenses incurred, on the grounds that they are exorbitant, unnecessary, wasteful, extravagant, or incurred in the abuse of discretion or in bad faith, or are of a nonrecurring character not likely to recur in the

[57] A.J.G. Priest, Principles of Public Utility Regulation 1969, Vol. I, pp. 422-23.

> future, has the commission a reasonable discretion to disallow any part of the expenses actually incurred.

Alabama Pub. Serv. Comm'n v. Southern Bell Tel. & Tel. Co., 253 Ala. 1, 42 So.2d 655, 674 (1949) cited with approval, State ex rel. Utils. Comm'n. v. Intervenor Residents, 305 N.C. 62, 77, 286 S.E.2d 770, 779 (1982).

This standard against which costs recovery challenges are measured has elements qualitatively and quantitatively distinct and more rigorous than a tort standard of due care. The expert witnesses sponsored in this case failed to support allegations of discrete actions constituting imprudence. For its equitable sharing disallowance, the Public Staff proceeded on an equitable sharing theory, not on a theory of imprudence. AGO witness Wittliff on cross-examination failed to show what DEC should have done differently to remediate CCR, when it should have acted, and what the cost of such alternative conduct should have been. While AGO witness Wittliff filed forceful allegations on paper in the prehearing filings, much as was the case in the DEP rate hearing, his support of that testimony from the stand on cross examination was not persuasive.[58] Public Staff witness Junis likewise could not identify costs DEC would have incurred to remediate prior to 2015.[59] Without record evidence from parties advocating disallowances

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[58] Q. Beginning on line 16, you state, "However, when it came to making changes to its own unlined surface impoundments, the Company chose not to move forward with the industry, but instead chose to add more and more coal ash to the unlined impoundments despite the longstanding seepage and groundwater issues at its facilities."

Did I read that correctly?

A. You did.

Q. Mr. Wittliff, despite your 30 years of experience as an engineer, I am correct, am I not, that if I look through the entirety of your testimony in this case and all of your exhibits, I will not find any engineering analysis of what exactly that DEC should have done, when it should have done it, where it should have done it, and how much it would have cost with respect to the lines in the testimony that I just read you, will I?

A. Say that again, please.

Q. Yes, sir. You make a contention, on page 10 of your testimony, on line 17 through 20 that I just read, alleging that DEC chose not to move forward with the industry, but instead chose to move more and more coal ash to unlined impoundments.

My question is, if I want to look at how I should have moved forward with the industry, where I should have done it, when I should have done it, how much it should have cost me - and by "me," I'm referring to DEC - I cannot find those answers anywhere in your prefiled testimony, can I?

A. No.

Tr. Vol. 11, pp. 283-84

[59] "The coal ash-related environmental violations have a cost. Corrective actions to address environmental impacts under CAMA and the Environmental Protection Agency's (EPA) Coal Combustion Residuals Final Rule (CCR Rule), including ultimately closure of all DEC ash basins, will remedy the environmental violations. Therefore, it is not feasible to identify all the costs that would have been incurred to remedy violations under the pre-existing environmental regulations and laws, such as 15A NCAC 02L (2L rules) and North Carolina General Statute 143-215.1, if CAMA and the CCR Rule were not in effect. . . . There is no doubt that substantial assessment and remedial costs would have been incurred without CAMA and the CCR Rule, but, in my opinion, those costs cannot be quantified without undue speculation."

Tr. Vol. 26, pp. 646-47

for failure to take CCR remediation steps prior to 2015 pursuant to the burden of proof theory or an unsupported "failure to exercise due care standard" of what action DEC should have taken, when it should have acted, and what the costs would have been, the Commission cannot approve such specific disallowances. Attempts to identify years-old hypothetical past costs, for example, by allocating tons of CCRs to formulate inexact allocation percentages to be applied to 2015-2017 costs is to rely upon guesswork that simply is legally and equitably deficient.[60]

Coal ash located within basins above levels saturated by water and unaffected by the contours of the bottom of the impoundment can be removed at a cost lower than coal at lower levels. Costs of replacement repositories will vary depending on land costs, location, regulatory requirements and site preparation costs. Transportation costs will vary depending on distance, market conditions, regulatory requirements and timing of incurrence.

Efforts to identify what DEC should have done prior to EPA CCR and CAMA, when it should have done so and what the costs should have been even with the benefit of 20/20 hindsight pose insurmountable obstacles. CCR remediation even under the supervision of NC DEQ is a site-specific undertaking with procedures that have evolved over time and continue to do so. Without statutory or regulatory standards and guidelines to follow, no one can say what the prudent course would have been even if one acts on the assumption that DEC was imprudent to await promulgation of the definitive environmental regulatory requirements.

Under EPA CCR regulations and CAMA requirements, the prevalent remediation remedy is dewatering, excavation and removal or cap-in-place. These explicit, express requirements depend heavily on NC DEQ oversight and supervision. The remediation steps must be completed in compliance with deadlines and substantial collaboration between NC DEQ and DEC with respect to permitting. Compliance will occur as far into the future as 2028. No one can predict today how compliance will be accomplished or what these future compliance costs will be. The decision by NC DEQ on whether cap-in-place for eligible impoundments versus CCR removal has yet to be made. Yet Intervenors ask the Commission to look backward where the regulatory requirements were not in place and therefore unknown and speculate what it would have cost to comply so as to impose the imprudence disallowance. Having failed to even attempt to quantify such a disallowance, Intervenors' theory is without probative support and must be rejected.

Without any requirement such as EPA CCR rules or CAMA to remediate CCRs stored in unlined pits simply because unlined pits posed "potential" threats to the environment, Intervenors must "pick a date" when in their opinion such remediation should have been undertaken. Likewise, Intervenors apparently assume the remediation

[60] When quantifying quantities of CCR for purposes of cap-in-place, utilities rely upon linear measurements, not tonnage.

remedy would have been dewatering, excavation and removal or perhaps cap-in-place, even though they do not agree on which of these alternatives is appropriate for each basin. No support for this assumption exists. Without requirements such as those of EPA CCRs and CAMA, DEC logically would have attempted to investigate each unlined repository to determine insofar as possible the extent to which contamination was occurring or had the potential to occur. Absent evidence of actual or probable future contamination, DEC would have been remiss in spending millions of dollars to remediate or to choose the most expensive remediation alternative.

As to impoundments where contamination was occurring or potentially would occur, remedies far short of complete excavation such as installing water extraction methods beyond the impoundment to remove water or to excavate contaminated soil were available and arguably should have been employed as a least cost solution.

Any CCR impoundment leaks, whether lined or unlined. The underlying soil composition and subsurface groundwater flow direction for each site are significant considerations in assessing risk of harmful contamination from CCR constituents. Piedmont red clay acts as a natural sealant. Unless CCR contaminants in excess of proscribed levels migrate beyond boundaries outside repositories, no actionable threat occurs. Monitoring wells provide tools to measure migration of harmful constituents. Determinations of naturally occurring levels of CCR contaminants must be made to determine whether measurements in excess of published standards, if any, originate at the impoundment.

Determining the number and placement of monitoring wells, not an inexpensive endeavor (Tr. Vol. 26, p. 92), is an inexact science. The prevalent and cost-effective process is to install monitoring wells iteratively to best identify harmful groundwater contamination. Tr. Vol. 26, pp. 92-93. Evidence of excessive constituent levels up gradient of impoundments tells nothing about impoundment contamination but is necessary to identify naturally occurring constituents that may or may not exist down gradient. Unlike synthetic contaminants like dry cleaning fluid or nuclear waste where evidence of its presence in groundwater can be tied to a source of pollution, all the potentially harmful elements from coal ash occur naturally in the ambient environment. Tr. Vol. 26, pp. 92-93. Underground water flows may dissipate excessive levels of CCR contaminants through natural attenuation to those below standard thresholds. There may be no receptors in the vicinity of the impoundment.

The best evidence of the difficulty in determining what DEC should have done, when it should have done so and what the cost should have been prior to 2015 is the significant dispute that arises in this case over what DEC should have done, when it should have done so and what the costs should be with respect to the actual 2015-2017 costs. DEC actually has incurred these costs in its efforts to comply with EPA CCR and CAMA published standards and requirements undertaken under NC DEQ's supervision and guidance. Parties to this case hotly dispute where replacement repositories should be constructed, when and how CCRs should have been transported, and which CCRs should have been designated for beneficial reuse.

Consequently, the Commission determines that efforts to recreate the past as no party has been able to do so is a fruitless endeavor that the Commission is unable and unwilling to undertake.

Additional complications to certain Intervenors' theory that disallowances to 2015-2017 CCR remediation costs should be made because DEC failed to begin remediation or alternative CCR storage earlier magnify the fatal flaw in the theory. From an accounting cost recovery perspective, the Commission authorizes establishment of an ARO, defers costs for remediation, and later amortizes these deferred costs over five years. DEC began to incur the remediation costs in 2015 and will continue to do so under EPA CCR and CAMA regimes until 2028. Consequently, under procedures being followed, cost recovery will occur through 2033. If, under certain Intervenors' theory, DEC should have begun remediation in 2006 (hypothetically, because Intervenors cannot identify the starting date under their theory), DEC would still have been incurring CCR remediation costs during the test year and would have been amortizing CCR remediation costs from prior years. Consequently, ratepayers paying rates established in this case could very well face the possibility of being no better off under Intervenors' alternative, unsubstantiated theory. Perhaps, arguably, DEC should have established a coal ash remediation cost ARO earlier in anticipation of a future requirement to undertake remediation efforts, and costs not so accounted for should be disallowed. However, the Commission's practice is not only to approve the establishment of the ARO but to defer the costs accounted for in the ARO for later recovery in a general rate case. Theories relied upon to recreate the past based on hypothetical scenarios all depend on guesswork and subjective factual constructs that are beyond the ratemaking standards this Commission must employ.

The burden of proof to show that rates are just and reasonable is always on the utility. See N.C. Gen. Stat. § 62-134(c). Intervenors, however, have a burden of production in the event that they dispute an aspect of the utility's prima facie case. See, e.g., State ex rel. Utils. Comm'n v. Conservation Council, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (utility's costs are "presumed to be reasonable" unless challenged); State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses…."). If the Intervenor meets its burden of production, the ultimate burden of persuasion reverts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c).

The Commission has consistently followed this shifting burden framework. See, e.g., DEC Remand Order, (Docket No. E-2, Sub 1142) p. 34. In practice this means that Intervenors may not rest merely on arguments and theories, they must adduce actual evidence challenging some aspect of the Company's cost recovery case. Further, that evidence must support the Intervenor's challenge under the substantive standard established by North Carolina law. Evidence predicated on 20/20 hindsight is insufficient to effectuate a prudence challenge, inasmuch as the substantive prudence standard forbids hindsight analysis.

D. Conclusion with respect to January 1, 2015 - December 31, 2017 Costs

The Commission determines that the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that the coal ash basin closure costs it actually incurred from January 1, 2015 through December 31, 2017 are recoverable and that a return, but one reduced to recognize a mismanagement penalty, is warranted, and that the Commission with contrasting evidence on the merits, with exception addressed below, authorizes recovery.

First, Company witness Kerin demonstrated that the Company's coal ash management historical practices (i.e., pre-CCR Rule and pre-CAMA) have generally comported with industry practices and then-applicable regulations, especially in this region of the country. See, e.g., Tr. Vol. 14, pp. 99-100, 135. The Commission determines that compliance with industry standards is an important but not the sole criterion in determining the recoverability of CCR remediation costs. As part of his work to bring DEC into compliance with the new CCR Rule and CAMA, witness Kerin helped establish and participated in an industry peer group consisting of representatives of, for example, Dominion and Southern Company, and his interaction with that group and his investigation of practices at other Duke Energy Corporation-affiliated utilities confirm his conclusion that the Company's practice was not out of line with the overall industry practice. Id. at 96-97. As witness Kerin testified, when he looked at all of the practices at the Duke Energy Corporation utilities, in multiple states, "Indiana, Ohio, North Carolina, South Carolina, and Florida, all those practices were the same, so that led me to believe that all those [companies], prior to becoming Duke Energy companies, were managing their ash and their ash basins in the same manner." Id. at 158-59. He made the same observation concerning the peer group of companies – AEP, Dominion, the Southern Companies and TVA – and "their practices were similar." Id. at 159. He concluded: "So that whole group of states across the eastern part of the United States, we were operating our basins in the same fashion." Id.

Witness Kerin's testimony on this point was not seriously or credibly controverted by any Intervenor. Indeed, AGO witness Wittliff was not able to specify exactly how the Company should have acted differently in managing its coal ash to be consistent with industry, at which sites it should have taken those actions, and how much those actions would have cost the Company. Tr. Vol. 11, pp. 283-89. Witness Wittliff also presented no credible evidence showing DEC's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time other than his own, subjective allegations. Tr. Vol. 24, p. 121.

Moreover, key documents that Intervenors used in cross-examination in an effort to rebut witness Kerin's testimony contain provisions that in part support, to some extent at least, his testimony and these findings. For example:

- Los Alamos Laboratory Report (1979): "Much of the ash produced by coal ash combustion is discharged into ash ponds." Sierra Club – Kerin Cross Ex. 3, p. 6.
- EPRI Coal Ash Disposal Manual (1981): No coal ash was landfilled in either North or South Carolina; rather, all of it was stored in ponds. Sierra Club – Kerin Cross Ex. 4, Table 3-1, pp. 3-7. Further, 81% of the coal ash produced in the Southeast was placed in ponds. Id. at 3-8.
- EPA Report to Congress (1988): This Report (Sierra Club – Kerin Cross Ex. 5) confirms that the Company's disposal of coal ash in ponds conformed in large measure to industry practice. The Report refers to ponds as "surface impoundments" Id. at 4-11, and notes that CCR waste management practices varied by region, and that in the South (EPA Region 4, which includes North and South Carolina) 95% of the plants manage their CCRs on-site. Id. at 4-23. The Report continues, "On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant." Id. It noted further that "access to abundant, inexpensive supplies of water … [in Region 4] often made it economical to use this management option." Id. at 4-20.

The 1988 EPA Report also indicates that "until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems," and that "liner use has been increasing in recent years." Id. at 4-33. Intervenors point to these statements to argue that the Company's continued use of unlined ponds was outside standard industry practice and is otherwise imprudent. The Commission disagrees. The Report notes, for example, that 87% of surface impoundments were unlined (id. at 4-33), and that neither North Carolina nor South Carolina required liners. Id. at 4-3. It also notes that one-fifth of waste generated by coal-fired power plants was reused, and "the remaining four-fifths are typically disposed in surface impoundments or landfills." Id. at ES-2. The Report thus validates witness Kerin's testimony that "unlined basins were the industry standard" at that time. Tr. Vol. 24, pp. 128-29. As he stated, "the EPA report focused on new landfills and surface impoundments, while DEC last constructed a new ash basin in 1982." Id. at 129 (emphasis in original). This was six years before the EPA Report was submitted to Congress. As witness Kerin stated further, in the DEP case AGO witness Wittliff testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, "because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" Id. at 122. Finally, witness Kerin's conclusion is supported by the preamble to the CCR Rule itself. See Public Staff Kerin Cross-Examination Ex. 4.

Based upon similar evidence in the DEP case, the Commission found that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit in coal ash basins, and such basins were constructed and used at all of the Company's coal-fired generating units." 2018 DEP Rate Order, p. 142. This finding and witness Kerin's testimony are also consistent with the Commission's findings in the 2016 DNCP Rate Order: "DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories)." 2016 DNCP Rate Order, p. 60.

It is undisputed that there will be a natural flow from an unlined basin into groundwater. This is a function of basic science. Tr. Vol. 13, p. 58. As Company witness Wells testified:

> Earthen basins and dike walls are prone to the movement of liquid through porous features within those structures through a process known as seepage. Such seepage is common, and, to a degree, is necessary to maintain the stability of an earthen dam or dike wall; otherwise they become saturated, which may reduce margins of safety with respect to their structural integrity.

Tr. Vol. 24, p. 246. Accordingly, seepage from the Company's unlined ash basins – basins that complied with industry standards and the then-applicable regulatory requirements – is part of the "normal operation" of the basins. This evidence of the Company's historical compliance establishes that, except in limited fashion, its past coal ash management practices did not cause it to incur in the January 1, 2015 – December 31, 2017 timeframe unjustified costs to comply with current laws and regulations. Tr. Vol. 14, pp. 100-01.

Second, witness Kerin's testimony established that in large measure the costs were reasonable and prudent. In light of the evidentiary presumptions and shifting burden of production and persuasion, and based on the Commission's assessment of the credibility of the witnesses opining on the facts and policy considerations at issue, the Commission relies heavily on his testimony. The testimony of other Company witnesses, including witness Wells, will be discussed in greater detail in the sections of this order dealing with the Public Staff's specific disallowance recommendations. Witness Kerin's testimony was credible, demonstrated command of the subject matter (he testified, after all, that he had "lived" with that "company-specific subject matter every day for the past four years" (Tr. Vol. 24, p. 92), and the Commission determined in the 2018 DEP Rate Order that he has "'lived' this project since its inception," (2018 DEP Rate Order, p. 187), and the Commission concludes that his conclusions were not dislodged after being subjected to vigorous cross-examination.

Third, witness Kerin's testimony establishes that the capitalized costs for which the Company seeks recovery are eligible for a return and, at least to the extent they are capital in nature, were used and useful. These costs were expended to comply with the CCR Rule and CAMA, along with consent agreements that require the Company to implement corrective actions consistent with either or both of those regulatory requirements. Tr. Vol. 14, p. 115. Capital expenditures undertaken to enable compliance with the law qualify as "used and useful," in that the Company does not have the option to fail to comply, and, as indicated in the testimony of Company witness Wright, are routinely recoverable in rates. Tr. Vol. 14, p. 115; Tr. Vol. 12, p. 131. Further, witness Kerin's testimony (see Tr. Vol. 14, p. 135 and Kerin Ex. 10 and Ex. 11) details the "core components" of the costs incurred. These include, for example:

- With respect to the Allen and Belews Creek Plants' coal ash basins, oversight and environmental health and safety (EHS) activities, engineering and basin closure projects;
- With respect to the Buck Plant's coal ash basins, EHS activities, basin closure costs, mobilization and beneficiation costs;
- With respect to the Cliffside Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, basin support projects, inspections and maintenance, and EHS activities;
- With respect to the Dan River Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, landfill construction, engineering closure costs, and EHS activities;
- With respect to the Marshall Plant's coal ash basins, EHS activities, inspections and maintenance;
- With respect to the Riverbend Plant's coal ash basins, ash processing, water management, and EHS activities; and
- With respect to the W.S. Lee Plant's coal ash basins, mobilization, ash processing, and engineering closure plans.

Witness Kerin testified further that mandated closure of the existing coal ash basins meant that the modifications had to be made to their associated power plants, so as to direct storm water flow away from the ash basins and to cease bottom ash and fly ash sluice flow to the basins. Tr. Vol. 14, p. 133. In addition, other process streams must be directed away from the coal ash basins to facilitate de-watering and closure. Id.

Witness Kerin and his supporting exhibits describe costs expended to facilitate the Company's handling and storage of coal ash, so as to conform to the new legal requirements imposed on the Company resulting from the promulgation of the CCR Rule and the passage of CAMA. DEC is subject to these new legal requirements and must handle and store coal ash in a manner that complies with them. As such, except as detailed below, the capital costs of compliance are "used and useful," and the Company is authorized to recover them along with other costs accounted for in the ARO, along with a return as adjusted below on its outlay of these funds.

1. Intervenor Challenges to Cost Recovery

Intervenors have mounted challenges to the Company's recovery (with a return) of its already-incurred coal ash basin closure costs on two levels. First, in a manner that departs from the prudence framework the Commission established in the 1988 DEP Rate Case, the AGO, through witness Wittliff; CUCA, through witness O'Donnell; and the Public Staff, through witness Maness, all advocate that costs be disallowed even without a detailed analysis of the specific costs the Company has submitted for recovery.[61] Second, the Public Staff (and only the Public Staff) proposes to disallow specific costs incurred through the testimony of witnesses Garrett and Moore, and Junis, thus at least attempting to follow the Commission's prudence framework.

However, the Commission determines that these approaches are not appropriate, and these proposed specific disallowances are not approved.

2. AGO/CUCA Approach: The Company "Caused" CAMA

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. He stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. In contradiction to its witness, the AGO in its brief asserted that all the CCR cost recovery DEC seeks in this case is imprudent. Not only has the AGO been unable to quantify the costs DEC should have incurred prior to 2015, it has failed to sponsor a witness that can support its theory of the case. While purporting to represent consumers, the AGO's theories and recommended disallowances are inconsistent with those of the Public Staff, tasked with representing the same constituency.

Witness Wittliff admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. However, witness Wittliff continued to pose the theory that the Company "caused" CAMA, and while he cannot point to imprudent action on the part of DEC in undertaking to comply with CAMA, the fact that the Company "caused" the statute to be enacted affects its ability to recover its CAMA-related costs. Tr. Vol. 11, pp. 239, 248-50, 272. CUCA witness O'Donnell agrees. Tr. Vol. 18, pp. 59-60 (Company caused CAMA and therefore should not recover any CAMA cost).

In these witnesses' view, CAMA sets a more aggressive coal ash basin closure schedule for certain of the Company's basins than would have been set under the CCR Rule alone, and the more aggressive schedule leads, again in their view, to higher costs. Witness Wittliff testified that he "[didn't] know quantitatively, because [he] didn't do that kind of analysis," in regard to what costs the Company would have eventually been

[61] Sierra Club witness Quarles asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from DEC's ash basins would reduce the concentrations and extent of this contamination. Tr. Vol. 6, pp. 17-118; 119-27. Witness Quarles made no effort to quantify the economic impact of his recommendation, which would increase cost to customers. The Commission is persuaded by the evidence presented by witness Kerin and witness Moore that the closure plans for the Allen and Marshall Plants are appropriate. DEQ will be responsible for determining which closure plans are appropriate for Allen and Marshall. The Commission determines that the associated expense for Allen and Marshall is reasonable and prudent.

required to undertake by the CCR Rule and CAMA, despite any exceedances, violations, criminal prosecutions, and civil and administrative lawsuits. Tr. Vol. 11, pp. 282-83.[62] Accordingly, the Commission determines that witness Wittliff's opinion cannot legitimately support disallowances, because it fails with respect to the prudence review framework the Commission established in the 1988 DEP Rate Case: (1) it fails to identify specific and discrete instances of imprudence; (2) it fails to demonstrate the existence of prudent alternatives; and (3) most importantly, it fails to quantify the effects by calculating imprudently incurred costs.

Witness O'Donnell proposes a 75% disallowance, but he does so predicated not on a calculation of "imprudently incurred costs" as required by the Commission's framework, but rather based on what he terms a "financial analysis" through comparison of the size of the ARO established by the Company to capture coal ash basin closure expense associated with CCR Rule and CAMA compliance with the AROs established by other utilities to capture their coal ash basin closure expense. This "calculation" is unpersuasive, however, as demonstrated by witness Kerin, (see Tr. Vol. 24, pp. 124-28), and as the Commission determined in the DEP case. See 2018 DEP Rate Order, p. 196. In particular, the analysis lacks any attempt by witness O'Donnell to account for the differences in which different utilities may have valued their closure cost estimates, or the differences in the timing of their estimates. As the Commission held in the 1988 DEP Rate Order, industry comparisons, even if relevant, are "of little value in determining specific acts of imprudence." 1988 DEP Rate Order, p. 56. The Commission agreed with the Company's witness that "[t]he flaw in industry comparisons … is that there are unique conditions on every nuclear project so that no projects are exactly comparable" (id.), and the same applies to AROs established by different utilities to capture their specific coal ash basin closure costs. Witness Kerin indicates, and the Commission agrees, that this renders witness O'Donnell's "analysis" without significant probative value – it is not a true apples-to-apples comparison of the utilities' AROs.

A more fundamental reason demonstrates why the Commission determines it should not accept the opinions of witnesses Wittliff and O'Donnell – the notion that the Company was the direct cause of CAMA is of limited legal basis. Witness O'Donnell presents no evidence of such direct causation, and witness Wittliff appears to base his opinion on a draft preamble to the Senate bill (Tr. Vol. 11, pp. 240, 248-50), notwithstanding the fact that this preamble is not present in the final ratified bill.[63] Moreover, in North Carolina, legislative intent is ascertained by the plain words of the statute. Rhyne v. K-Mart Corp., 149 N.C. App. 672, 562 S.E.2d 82 (2002). "Legislative history" of the type seemingly relied upon by witness Wittliff is legally impermissive. In State v. Evans, 145 N.C. App. 324, 550 S.E.2d 853 (2001), the Court stated:

[62] The AGO complains that the Commission imposes an inappropriate burden upon it to offer evidence to quantify the disallowances it advocates. The AGO cannot legitimately assert that the burden is unfair when it has failed to undertake the task of attempting to elicit that evidence. The AGO has undertaken substantial discovery of DEC in this case. Based on the omissions in its presentation, the AGO apparently failed to "close the loop" in seeking to elicit evidence on what it would have cost to take the remediation steps it alleges DEC should have taken prior to 2015.

[63] See N.C. Gen. Stat. § 130A-309.200, et seq.

> While the cardinal principle of statutory construction is that the words of the statute must be given the meaning which will carry out the intent of the Legislature . . . . [t]estimony, even by members of the Legislature which adopted the statute, as to its purpose and the construction intended to be given by the Legislature to its terms, is not competent evidence upon which the court can make its determination as to the meaning of the statutory provision.
>
> Thus, "[e]ven the commentaries printed with the North Carolina General Statutes, which were not enacted into law by the General Assembly, are not treated as binding authority by this Court." Accordingly, press releases and commission recommendations offered by defendant as evidence of the punitive purpose behind [the statute] are in no manner binding authority on this Court.

145 N.C. App. at 329-30, 550 S.E.2d at 857 (citations omitted). Accord. Elec. Supply Co. of Durham v. Swain Elec. Co., 328 N.C. 651, 657, 403 S.E.2d 291, 295 (1991); Styres v. Phillips, 277 N.C. 460, 472, 178 S.E.2d 583, 590 (1971) ("The intention of the legislature cannot be shown by the testimony of a member; it must be drawn from the construction of its acts.").[64]

Even if the actions or inactions of DEC or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so – and it did not. The legislature does not operate in a vacuum. Rather, it operates within the context of N.C. Gen. Stat. § 62-133, in which prudently incurred costs are recoverable. Had it intended to disavow the routine cost recovery standard, it can be expected that the legislature would have had to do so explicitly. Accordingly, witnesses Wittliff and O'Donnell theories of punitive causation do not comport with the controlling law of this state.

3. The Public Staff's "Equitable Sharing" Concept

In this case, as in the 2018 DEP Rate Case, the Public Staff advocates an "equitable sharing" of coal ash basin closure costs. The Public Staff's equitable sharing

[64] In Styres v. Phillips, the Supreme Court also stated that "the rule is that ordinarily the intent of the legislature is indicated by its actions, and not by its failure to act." Styres, 277 N.C. at 472, 178 S.E.2d at 590. Accordingly, the suggestion through cross-examination questions by the AGO (see, e.g., Tr. Vol. 13, p. 22) that as CAMA does not contain an express provision mandating cost recovery of compliance costs, the General Assembly did not intend for the statute to allow such costs, is also without any basis. To the extent that any such evidence is competent, the most relevant evidence regarding the General Assembly's failure to act is the fact that on two separate occasions the General Assembly was presented with the opportunity to mandate non-recoverability of compliance costs, and on both occasions the provision so stating did not pass.

proposal is supported by witness Maness. Tr. Vol. 22, pp. 70-85. Witness Maness achieves the sharing in the same manner in which he implemented the Public Staff's 50-50 sharing proposal in the 2018 DEP Case. First, he removes the unamortized coal ash basin closure costs from rate base, thereby, through that step, eliminating any return on that unamortized balance. Id. at 72. The second step is to choose an amortization period that will result in the desired level of "sharing." Id. The sharing level that the Public Staff and witness Maness deem "equitable" is 51% to the Company and 49% to customers. Id. at 84. Mathematically that results in a 27-year amortization period (id.), although, when adjusted for the rate of return to which the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case, the amortization period is reduced to 25 years. Id. at 153. Even under the 25-year amortization period, however, the sharing level remains 51% to the Company and 49% to customers. Id. at 162.

The Commission chose not to accept the "equitable sharing" concept in the 2018 DEP Case, and does so again, on the same basis.

First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 …." 2018 DEP Rate Order, p. 189.

Black's Law Dictionary defines an "arbitrary and capricious" decision as one which, inter alia, is "without determining principle." See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851 (1997). The Commission can discern no "determining principle" in the Public Staff's "equitable sharing" proposal. As such, were the Commission to adopt it, the Commission's action would be subject to an arbitrary and capricious attack and likely subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 718 S.E.2d 152 (2011), in which the Court held that it was arbitrary and capricious for a municipal body to "cherry pick" a standard without providing any basis of any particular determining principle. Sanchez, 211 N.C. App. at 580, 710 S.E.2d at 354. In this case, the Beaufort Historic Preservation Commission (BHPC) attempted to limit the construction of petitioner's home to 24 feet in height "without the use of any determining principle from the BHPC guidelines." Id. at 582, 710 S.E.2d at 355. Rather, the BHPC members based the standard "on their own personal preferences," with each member providing a manner of re-working the project's construction to comply with a 24-foot height maximum, but none providing a reason as to why 24 feet when the height "could be a different number …." Id. at 581 (emphasis in original). Thus, while the BHPC members could provide a way to arrive at the height maximum, they could not provide a "why" for that particular height maximum. Failure to provide a determining principle for the height maximum itself rendered the BHPC's decision arbitrary and capricious. Id. at 582.

Ultimately, the Public Staff, through witness Maness, indicates that "what is and what is not allowed in rate base is within the legal discretion of the Commission to decide." Tr. Vol. 22, p. 73. The Public Staff overstates the Commission's discretion, and to the extent the Commission possesses such discretion, the Commission chooses not to exercise it in the manner the Public Staff advocates. To understand exactly how, it is necessary first to examine the Public Staff's purported rationales for its sharing proposal. There are two: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Junis, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 71-72.

As to the first asserted predicate, the Company disputes such "failures," as set out in the testimony of Company witness Kerin. The Commission credits Kerin's testimony, as detailed below, but whether or not the Company were guilty of some sort of violation is insufficient to justify the Public Staff's 51/49 sharing proposal. Witness Maness admitted that these alleged acts or failures to act are related to past operations. Tr. Vol. 22, p. 80. No persuasive evidence exists that any of these actions or inactions caused discrete expenditures by the Company to comply with its CCR Rule and CAMA obligations, which are the costs that the Company seeks to recover. Past actions, even if imprudent in this context must result in quantifiable costs, which the Public Staff has not shown. Therefore, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact. 1988 DEP Rate Order, p. 15. The Public Staff has made no such demonstration in this case, and no such demonstration with respect to the Public Staff's 51/49 sharing arrangement.

Apart from his specific recommendation regarding disallowance of groundwater remediation expense (discussed below), witness Junis' testimony does not link the past actions of the Company to the costs it seeks to recover. As Company witness Wright indicates, to link alleged past "violations" to current compliance costs in the factual context of this case is to "put the Company in an untenable situation." Tr. Vol. 13, p. 39.

Past violations may well be imprudent, but with respect to the "question of responding to new regulations and new standards, that is a totally separate question." Id. The Commission agrees with this distinction. In keeping with its decision in the 1988 DEP Rate Order, this aspect of which was affirmed by the North Carolina Supreme Court, to permit disallowance there must an actual expenditure shown to be imprudently incurred.

The Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's equitable sharing proposal would still apply. As witness Maness testified, "[E]ven if 'prudent'" (Tr. Vol. 22, p. 126), the Public Staff would still find it "appropriate to have the shareholders of those companies bear a greater share of the cleanup costs under an equitable sharing approach." Id. Accordingly, the predominant rationale for the Public

Staff's proposal is witness Maness' second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 72.

Witness Maness overstates his position – as witness Wright notes, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 12, pp. 156-21–156-22), and, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. The Commission determines that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal.

It appears that witness Maness' rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to N.C. Gen. Stat. § 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are … the 'reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ….'" Tr. Vol. 22, p. 73. He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." Id.

DEC and the Public Staff stridently debate whether the 2015-2017 CCR remediation costs if found used and useful and otherwise meet the test for amortization with a return on the unamortized balance "must" or "may" be approved. The Public Staff argues that approval of a return is discretionary. The Commission determines it unnecessary to determine whether the costs must receive a return on the unamortized balance. In its discretion, as expressly authorized by N.C. Gen. Stat. § 62-133(d), with the exception addressed below, it approves a return.

DEC argues that deferred 2015-2017 CCR remediation costs accounted for in an ARO as authorized by the Commission in its 2018 order should be amortized over five years and should earn a return on the unamortized balance. The Public Staff argues that these ARO costs should be amortized over 25 years with no return based primarily on an equitable sharing theory. In support of these parties' contrasting positions and in order to challenge the merits of their opposition, the parties laboriously debate issues of used and useful, "entitled" versus "eligible" for earning a return, plant in service versus working capital, capital costs versus expenses, etc. The parties arduously debate the applicability to this issue of cases addressing an abandoned sewage treatment plant, costs of discontinued nuclear projects, and manufactured natural gas remediation costs.

No witness argues that the Commission lacks the discretion to follow the precedent it established in the two previous cases, DNCP and DEP, where it addressed the issue of amortizing deferred ARO CCR remediation costs over five years and a return on the unamortized balance. No witness argues that the law forbids the Commission to authorize a return on the unamortized balance. The Commission chooses to exercise its discretion and authority under N.C. Gen. Stat. § 62-133(d) and follow its precedent here - amortize the ARO costs over five years and authorize a return on the unamortized balance. The Commission will address the lengthy arguments and debate, but determines that by and large the arguments are not particularly germane or dispositive to the Commission's decisions. The Commission will not accept the Public Staff equitable sharing argument primarily because the Commission determines in its discretion that amortization of the deferred ARO costs over 25 years is inequitable and finds inadequate support for a 50-50 or 51-49 sharing versus some other ratio. The justification for disallowance of 50% of the ARO costs is not persuasive. The Commission concludes that the Public Staff relies on the equitable sharing principle because it, like other Intervenors, has been unable to quantify a disallowance on the basis of the alleged DEC acts and omissions prior to 2015 providing the predicate for the requested disallowance. Instead, the Commission relies upon some of the evidence offered to support the equitable sharing theory to impose a management penalty as discussed below.

While arguments by the parties through analogy to cases on other issues provide some helpful context, the issue of amortization of deferred CCR remediation costs required to comply with EPA CCR requirements and CAMA is sui generis and distinguishable. These expenditures, as FERC and GAAP refer to them, are "costs" or an "asset" of remediation. They have been deemed by the Commission without objection as extraordinary, as not being recovered through current rates and have for those reasons been deferred. As such, they are investor-supplied funds, not ratepayer-supplied funds and under principles of equity, law and fairness are eligible for a return. Otherwise the investor supplying these funds is deprived of the time value of money and is inadequately compensated resulting in an increased risk and ultimately increasing the Company's cost of capital. The Commission in its discretion hereby authorizes a return, but discounts it as discussed below.

The nuclear discontinued plant costs, to the extent relevant to the issues in this case, are primarily so with respect to the Public Staff argument in support of equitable sharing. The Commission determines on balance that the support for equitable sharing the Public Staff argues these cases provide is unpersuasive. This is not to say that the Commission is of the opinion it could not approve an equitable sharing remedy in a given case outside the context of a nuclear plant discontinuance case, but this is not a nuclear plant discontinuance case and not one the Commission chooses to rely upon to authorize equitable sharing. The costs the electric utilities incurred at issue in those cases were for nuclear plants, that had they been placed on line and generated electricity would have been added to rate base as used and useful plant in service. Some of the costs were for plants actually placed on line but sized to serve more units than the units actually generating electricity and therefore constituted excess capacity or plant not "useful." The costs had never been placed in rate base as plant in service prior to the general rate cases at issue, and to the extent they were costs in abandoned nuclear facilities, they were facilities never used to generate electricity. Those are not the facts at issue here. None of the nuclear plant discontinuance cases either before the Commission or the courts on appeal held that to the extent a portion of the costs could be recovered, they were ineligible for any return on the undepreciated balance, just that the costs should not be added to rate base. In fact, in the past, the Commission has approved a return. Order dated September 24, 1982, Docket No. E-2, Sub 444. (Commission authorized recovery of costs associated with cancelled Harris Units 3 and 4 over a ten-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance.)

The costs of the sewage treatment plant at issue in Carolina Water were classified as abandoned plant. The plant long having been in service had been taken out of service, and it would never be used again because service would be provided by contract with a governmental agency. A portion of the original costs to build the plant had not been recovered through depreciation at the time of abandonment. That is not the factual situation in this case. Here there is a deferral of ARO CCR remediation costs. New costs were incurred in 2015-2016 in addition to creation or maintenance of the impoundment in prior years.[65]

The MFG case is somewhat analogous, but does not address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO. The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories. The MFG case was a Commission decision, one the Commission may follow or not as it determines appropriate. For reasons fully explained herein, it determines not to follow it.

As to Public Staff arguments that the ARO costs or assets were all "capitalized expenses," the Commission, were it necessary to resolve this issue, would disagree. For example, a significant portion of the costs compiled in the asset retirement obligation has been or will be spent on creation of lined landfills with synthetic liners or impermeable caps over existing impoundments. These structures are examples of long-lived assets and are capital in nature- not expenses. Another significant portion, had they not been accounted for in an ARO and deferred, would have been operating or other expenses.[66] However, while expenditure of costs outside of the ARO context that are deferred may

[65] The issues of earning on the abandoned wastewater treatment plant was not the major issue before the Court in the Carolina Water case. The ultimate issue before the Commission was whether the unrecovered costs of the sewage treatment plant should be treated as plant held for future use of abandoned plant. Discussion of this issue consisted of less than two pages in a 126-page order. The monetary consequences amounted to a few thousand dollars per year. Docket No. W-354, Sub 111, Order dated July 31, 1992, pp. 56-58. The facts at issue in the case are unlikely to be repeated. Under the Uniform System of Accounts, the costs of individual components, in many instances, are combined into classes for calculating depreciation rates and net salvage value. Within these classes many individual components retire before or after the end of their projected useful lives. These retirements affect the recalculated depreciation rates, but the individual components are not classified as abandoned plant. See Tr. Vol. 2, Doss Ex. 3. Hahne & Aliff, Accounting for Public Utilities § 6.04 pp. 6-8, 6-10, § 6.05[3] pp. 6-12.

[66] 2016 is the twelve month test year in this case. To the extent the Commission had not authorized deferral of the ARO in 2016, the non-capital portion of the CCR remediation costs to the extent reasonable and prudent would be recoverable dollar-for-dollar in the revenue requirement. The portion spent on capital projects to the extent comprising completed projects would be added to rate base and eligible to earn a return.

include what otherwise would be classified as "expenses," e.g., operating costs, when they are capitalized and by order of the Commission are deferred, they lose for ratemaking purposes the attributes of test year recurring "expenses" deemed recoverable through the rates then in effect that do not qualify for a return. To the extent they qualify for recovery "of" (versus recovery "on") test year expenses in a general rate case through N.C. Gen. Stat. § 62-133(b)(3), they are recoverable as "actual investment currently consumed through reasonable actual depreciation" (amortization) rather than traditional test year, recurring "reasonable operating expenses." The Commission determines that while sui generis these ARO costs in totality are more closely related to deferred production plant costs than deferred storm damage costs, for example.

In Footnote 2 on page 5 of the Public Staff brief, the Public Staff contends:

> [2] Thornburg I provides that the Commission has discretionary authority to award or deny a return on the unamortized balance. A subsequent decision of the North Carolina Supreme Court indicates such deferred operating expenses are not eligible for a return on the unamortized balance: "Costs for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base." State ex rel. Utils. Comm'n v. Carolina Water Serv., 335 N.C. 493, 508 (1994) (Carolina Water Service). This decision did not expressly overrule Thornburg I, but nonetheless suggests that a return on unamortized balance of a regulatory asset is not a discretionary matter for the Commission; instead it may be prohibited by law.[67] For purposes of the present Post-Hearing Brief, the Public Staff position is that under either the Thornburg I holding or the Carolina Water Service holding, there is no DEC entitlement to a return on the unamortized balance of its deferred coal ash costs.

The Commission finds the contention inaccurate that the cited cases deny the Commission discretion to authorize a return on a deferred CCR remediation ARO. The nuclear plant discontinuance costs at issue in Thornburg I were not "deferred operating expenses" like deferred CCR ARO costs, and the abandoned water treatment plant costs

[67] While the Public Staff suggests that authorizing a return on the unamortized balance might not be discretionary, this suggestion is belied by the Public Staff's alternative remedy for disallowing CCR remediation costs set forth on page 422 of its proposed order:

> Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $72.3 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. . . . Had the Commission not imposed this penalty, the deferred coal ash costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual amortization expense by approximately $14.46 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $72.3 million management penalty.

at issue in Carolina Water likewise were not deferred "regulatory asset" costs comparable to either deferred nuclear plant discontinuance costs or deferred CCR ARO costs.[68] The Commission notes that it has authorized deferral of capital costs in utility plant (e.g., combined cycle natural gas fired electric generating plants) completed and placed in service prior to the test year or prior to the end of the test year of a general rate case to prevent loss of recovery of costs. The costs so deferred are not test year recurring operating expenses but deferred capital costs, added to rate base and eligible for a full return. A used and useful analysis is appropriate to determine recovery of these costs. Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order)

The Public Staff also argues inaccurately and misleadingly that "it generally makes no regulatory sense to defer to a regulatory asset a cost that could be placed in rate base – deferral is used when necessary to prevent significant erosion of earnings, which is applicable to expenses but not to property that can be put in rate base; . . . ." In the Commission's December 22, 2016 order in the most recent DNCP general rate case, Docket No. E-22, Sub 532, the Commission approved a stipulation between the Company and the Public Staff to defer the post-in-service costs of the Warren County CC and the Brunswick County CC. These plant-in-service electric production assets had been placed in service prior to the end of the general rate case test year, and the deferral postponed the date on which depreciation costs began and permitted return on the full costs of the assets. This deferral related to property, not expenses.

From the outset, the Public Staff has acknowledged and recognized that the ARO costs do not fit into traditional categories: "The Public Staff believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements ... these very unique deferred expenses . . . the unusual circumstances of these costs . . . the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery." Tr. Vol. 18, pp. 300-01, Docket No. E-2, Sub 1142.

In the Commission's attempt to obtain a classification of the types of costs included in the ARO in the DEP case, witness Maness listed among others, site preparation, site infrastructure, construct a landfill, cap-in-place, capital expenditures related to equipment and facilities." Tr. Vol 19, p. 58. Under any analysis, these are not expenses but capital items. Had DEC not sought establishment of an ARO and deferral, it is incorrect that they would not have been added to plant in service and depreciated over their useful lives.

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[68] While the regulatory accounting concepts of creation of a "regulatory asset/liability" and "deferral" include a wide spectrum of cost categories, this Commission views differently costs incurred before the test year of a general rate case (like extraordinary storm costs) and costs otherwise recognizable as test year costs or expenses but deferred for non-traditional future recovery such as nuclear plant discontinuance costs that are not added to rate base but are nonetheless amortized over future years. Costs in the former category are deferred to prevent loss of recovery. Costs in the latter category generally are deferred to limit, reduce or postpone recovery.

In Docket No. E-2, Sub 1142, witness Maness was asked why certain ARO capital costs were not appropriately classified as used and useful.

Q. Just to be clear, one of the things we are doing -- we showed it up on the screen here yesterday - we are putting liners under these coal ash pits, right?
A. Yes, sir.
Q. And that's - and we are putting caps or proposing to put caps over some coal ash basins?
A. Yes.
Q. Isn't that used and useful expenditure to keep the coal ash where it belongs?
A. Well, that raises a number of interesting questions, and I can't pretend to be able to answer them in detail. I have been searching for some answers in the accounting literature and haven't found anything direct yet."
Tr. Vol. 19, pp. 65-66.

Upon being questioned and when given the opportunity to support its position that the deferred ARO costs are "expenses," the Public Staff simply was unable to do so.

When witness Maness was asked whether classifying the ARO costs as used and useful made any difference to the outcome of the case, he responded, "I don't think it makes any difference in this case." Tr. Vol. 19, p. 66. The Commission agrees.

The Commission does agree with the Public Staff and others that even if the ARO deferral costs are found used and useful and that a 9.9% rate of return on rate base is appropriate, the Commission nevertheless has authority to disallow a portion of the return on the ARO costs due to mismanagement. This is what the Commission has required, and it is legally justified in doing so.

As expressed through witness Maness' testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its equitable sharing concept. The Commission determines that Thornburg I provides less support for the equitable sharing the Public Staff advocates when viewed within the context of other cases addressing nuclear plant discontinuance costs. Greater context is found in Thornburg II, the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989).

The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing … [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, p. 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period, what the court classified as an operating expense[69] for the purposes of rate recovery under N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c), but no return. The Supreme Court, in a passage extensively quoted in witness Maness' testimony (Tr. Vol. 22, pp. 75-76), affirmed the Commission's decision, holding that N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c) were elastic enough to include non-recurring abandonment costs as utility test year "expense," and that N.C. Gen. Stat. § 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61. The Commission had not authorized a return on the costs at issue. The contested issue was recovery of not recovery on the nuclear investment costs.

In Thornburg I, the Court held specifically that the Commission's recovery of but no return on decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness' testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 22, p. 75), and that the Commission possesses discretion to implement this sharing.

There are, however, distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First this case does not involve "abandoned plant" or cancellation costs. Rather, it involves an asset retirement obligation and whether or not the unamortized balance is eligible for a return. As such, the authority that the Public Staff relies upon to support its "equitable sharing" concept is not directly on point. This is illustrated by examining the prior orders of this Commission and the subsequent Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris

[69] While the Court's use of the term "operating expense" is technically correct as referenced in the statute, the more precise term should have been "actual investment currently consumed through reasonable actual depreciation" (amortization) in N.C. Gen. Stat. § 62-133(b)(3). The costs at issue are not recurring operating and maintenance or other "expenses" expended in the test year. They are ever decreasing costs allowing a "return of," but not a "return on" the nuclear plant costs. See Tr. Vol. 9, pp. 115-131; Vol. 10, pp. 14-28.

Unit 1 costs were reasonable and prudent, and that determination in the 1988 DEP Rate Order was upheld by the Supreme Court. Thornburg II, 325 N.C. at 488-89, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million-worth – of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had ceased to construct to completion. The Commission found that while these $570 million in costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, pp. 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. 1988 DEP Reconsideration Order, pp. 2-3. The Commission did not (it says in the 1988 DEP Reconsideration Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held, (id. at 4-5), that it was appropriate to share the $570 million at issue, and it indicated that it came up with the allocation (essentially one-third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." The Commission held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with … [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The Supreme Court disagreed. It held that the Commission did not have the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. Thornburg II, 325 N.C. at 495. Accordingly, looking to the broader spectrum of Commission and Supreme Court precedent, the Commission determines not to approve the Public Staff's "equitable sharing" concept through reliance on the nuclear plant discontinuance cost cases.

4. ARO Accounting and "Used and Useful"

In the 2018 DEP Rate Case, the Public Staff argued that the Commission had the discretion to implement the "equitable sharing" concept based upon the Public Staff's interpretation of prior Commission orders and decisions of the North Carolina Supreme Court that permit equitable sharing in the case of abandoned nuclear plants or long out-of-use manufactured gas plants. As noted above and in the 2018 DEP Rate Order, the Commission determines not to approve the Public Staff equitable sharing recommendation. In the 2018 DEP Case, the Commission held to the contrary that

> Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets.

2018 DEP Rate Order, p. 196. In this case, Public Staff disputes this as a matter of accounting, and concludes on the basis of its interpretation of the accounting standards that the Company's coal ash basin closure expenditures cannot be classified as "used and useful." As it did in the 2018 DEP order, the Commission determines that it can authorize a return on the unamortized ARO costs.

The Public Staff's position is advanced by witness Maness. Starting from the premise that the Company "chose" to account for its coal ash basin closure costs through ARO accounting, witness Maness makes three basic points. First, he indicates that the Company's deferred coal ash basin closure costs placed in the ARO are more properly categorized as deferred expenses, in that the ARO is "a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses …." Tr. Vol. 22, p. 79. Second, he states that the fact that the Company classifies these costs as "working capital" is irrelevant, and merely a matter of convenience. Id. at 81. Third, he asserts that these costs cannot possibly be classified as "used and useful," because (in his view) that term applies only to utility plant, not expenses. Id. at 77. The Commission disagrees, but as the Public Staff agrees that the Commission possesses the discretion to approve a return on the unamortized balance of the deferred CCR remediation ARO costs, the Commission finds the debate for purposes of this case to be for the most part an academic one.

First, the Commission disagrees that the Company "chose" ARO accounting. The Commission has already so held in the 2018 DEP Case: "Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter." 2018 DEP Rate Order, p. 194.[70] Further, as Company witness Doss testified, in addition to GAAP requirements "the Company was also required to (and did) adhere to and apply the accounting guidance under … [the] Federal Energy Regulatory Commission ('FERC') Code of Federal Regulations ('CFR'), as well as Orders of this Commission." Tr. Vol. 12, p. 62. The Company's ARO accounting complies with the authoritative statements of GAAP, FERC, and this Commission.

Witness Doss provided an extended explanation of the GAAP, FERC, and deferral directives that govern the manner in which the Company established the ARO and has accounted for coal ash basin closure costs in the ARO. The Commission credits his explanation and testimony, which are un-contradicted.

a. <u>GAAP</u>

The CCR Rule and CAMA were new laws that compelled basin closure under GAAP.[71] As Company witness Doss indicated, "The closure obligation triggered ARO accounting requirements." Tr. Vol. 12, p. 63. He elaborated:

> Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing *or* <u>enacted</u> law …." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

<u>Id.</u> As he explained further (<u>id.</u> at 64-65), GAAP requires ARO accounting for the closure costs under ASC 410-20-15. Specifically, Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.
b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full

[70] As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity." <u>See</u> Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-7, Sub 723 (April 4, 2003), pp. 11-12.

[71] The applicable GAAP guidance is contained in Doss Rebuttal Ex. 1.

retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Upon recognition that ARO accounting is required, GAAP further indicates that the entity "shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability." ASC 410-20-25-5; see also Tr. Vol. 12, p. 20.

The reference in ASC 410-20-15-2(b) to environmental compliance costs in connection with "normal operation" highlights an important distinction in this case with respect to the Company's coal ash basin closure costs. GAAP distinguishes between costs associated with "normal" and "costs associated with improper" operation. The Company has demonstrated that "normal" operation applies.

The distinction is detailed in witness Doss' testimony. Subtopic 410-20 of the ARO guidance applies to "normal operation" (see ASC 410-20-15-2(b); Doss Rebuttal Ex. 1, p. 2 of 28), and permits their inclusion in an ARO. Subtopic 410-30 applies to improper operation (see ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, p. 2 of 28), and excludes them from an ARO. For example, as witness Doss testified, "Costs associated with the Company's Dan River spill … are covered by Subtopic 15-3(b), and, therefore, are not included in the coal ash basin closure ARO." Tr. Vol. 12, p. 66. This comports with the GAAP guidance itself, which notes that "a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not." See ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, pp. 2-3 of 28. The guidance notes further that the spillage costs are properly within the ARO, while costs resulting from the catastrophic accident are excluded. Id.

GAAP guidance notes that "whether an obligation results from the normal operation of a long-lived asset may require judgment." See ASC 410-20-55-7; Doss Rebuttal Ex. 1, p. 11 of 28. Witness Doss acknowledged this. Tr. Vol. 12, p. 111. But it is not unbridled or arbitrary judgment. To the contrary, the exercise of judgment is carefully circumscribed through internal and external controls.

Witness Doss described these controls at length in his testimony. He noted that "DEC has implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment … [and that decisions] of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document." Id. at 66-67. These decisions are reviewed internally by the Company's "Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." Id. at 67. Finally, any ARO-related cost classification is also reviewed by the Company's external auditor, Deloitte & Touche LLP, which in the course of its annual audit issues its opinions that the Company's financial statements are presented fairly in all material respects and in accordance with GAAP, and that the Company has effective internal control over financial reporting. Id. at 67-68.

The Commission determines that the evidence that the coal ash basin closure costs incurred by the Company, and for which it seeks recovery in this case, result from the "normal," non-catastrophic operation of the Company's coal ash basins is compelling. It is detailed above in connection with the Commission's discussion of the Company's prima facie case, and need not be repeated. The Company has demonstrated that its coal ash management practices, storage of CCR in unlined ash basins, complied with the then-applicable regulations and with industry practice. Seepage from unlined basins is therefore part of the "normal operation" of those basins.

b. FERC

Witness Doss also explained the FERC accounting guidance. He noted that the Company is regulated by FERC, and therefore required to use the FERC Uniform System of Accounts, which states, in relevant part:

> An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be

> stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

Tr. Vol. 12, p. 68. He noted further that the FERC Uniform System of Accounts General Instruction No. 25 requires that:

> a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101- Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230.

Id. at 68-69.

Commission's Deferral Order and Summary of Accounting Rules and Deferral

In 2003, after the Financial Accounting Standards Board required the implementation of the ARO accounting guidance, the Commission ruled in Docket No. E-7, Sub 723 "That the implementation of SFAS 143 [now codified as ASC 410] for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." See Order Granting Motion for Reconsideration and Allowing Deferral of Costs, Docket E-7, Sub 723 (August 8, 2003), p. 12. As witness Doss explains,

> The cash outflows to settle the ARO are not recorded as an expense of DE Carolinas. The Company has already recognized depreciation expense through the life of the asset and accretion expense over the period of expected settlement of the ARO, and these costs were capitalized previously as part of the Asset Retirement Cost related to the ARO. See ASC 410-20-25-5. However, in the case of DE Carolinas and pursuant to the Commission's Order in Docket No. E-7, Sub 723, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the deferred depreciation and accretion expense which has now been incurred as a cash outflow and which is "subject to the future orders of the Commission" as stated in the Order. Therefore, the Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-7, Sub 723.

Tr. Vol. 12, p. 70.

While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired. While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

c. The Savoy Letter

The Company's accounting of its coal ash costs has not occurred in a vacuum. Over 20 months before DEC filed its application to increase rates in this docket, it sent a letter to the Commission, copying the Public Staff, in which the Company detailed exactly how it was accounting for its coal ash basin closure costs. See Letter dated December 21, 2015 from Brian D. Savoy, the Company's SVP, Chief Accounting Officer, and Controller to Gail L. Mount, Chief Clerk (Savoy Letter), filed in Docket No. E-7, Sub 1110.[72] The Savoy Letter:

- Describes the GAAP and FERC accounting requirements regarding AROs;
- Describes the triggering events for the creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA;
- Indicates that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet;
- Indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets"; and
- Noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 … all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

Witnesses Fountain and McManeus were examined at length regarding the Savoy Letter at the evidentiary hearing. Tr. Vol. 9, pp. 117-24. That examination established, inter alia,

[72] This Docket was established on March 28, 2016 by order of the Commission, and the Savoy Letter placed therein, so as to acknowledge the Letter and allow other parties with interest to be made aware of it. See Order Acknowledging Receipt of Filing, Docket No. E-7, Sub 1110 (Mar. 28, 2016). The order recited that no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its Petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs. The Sub 1110 Docket has been consolidated with this rate case docket.

that basin closure costs, whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO; that such costs are extraordinary and not reflected in the Company's then-current rates; and, therefore, needed to be set aside and deferred so that the Company would not lose recovery of those costs "to the detriment of the stockholder." Id. at 123-24.

No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Intervenors have a burden of production when challenging the Company's costs. This principle equally applies to the accounting for costs. The Commission determines that the Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting, and the Commission agrees that based on its determinations on the merits that recovery is appropriate except as addressed below.

Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the … [utility] but have yet to be included for ratemaking purposes …." Lesser & Giacchino, p. 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised any objection.

Nor did the Public Staff or the AGO raise any objection when the Company made its formal deferral request in 2016. Tr. Vol. 9, p. 126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. p. 125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.

It is also incorrect as a matter of accounting. As witness Doss testified, "The Company has accounted for these costs as required under GAAP and FERC Uniform System of Accounts." Tr. Vol. 12, p. 71. Under GAAP, the costs (no matter what their classification) are capitalized pursuant to ASC 410-20-25-5. Id. at 70. Under FERC accounting, they are capitalized as well. Id. at 68-69. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not "expenses."

Likewise, witness Maness' criticism that these costs are placed in "working capital" is also not determinative. Witness Maness, without support and solely as a matter of opinion, states that the Company's inclusion of the deferred balance of coal ash basin closure costs in the "working capital" portion of rate base is merely a matter of convenience. Tr. Vol. 22, p. 81. He does not state that their inclusion in working capital is incorrect, merely that such inclusion is not determinative of the issue of whether the Company is entitled to a return on the unamortized balance. It appears that witness Maness has misunderstood the Company's position, as is evident from the testimony of witness McManeus, which the Commission also credits. She testified:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317. She elaborated further, indicating that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. Id. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

Finally, the Public Staff's notion that costs accounted for in an ARO, at least to the extent they relate to long lived capital assets, are expenses and therefore ineligible to be characterized as "used and useful" is inconsistent with ARO accounting, and also inconsistent with the law. The Commission has already decided that the Public Staff's legal position that "used and useful" property is confined to "plant" is incorrect. It held in the 2018 DEP Rate Case:

> As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:
>
>> Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service" … and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
>>
>> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.
>>
>> 285 N.C. at 414-15. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer-furnished, VEPCO holds that they are "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.

2018 DEP Rate Order, pp. 194-95.

In addition, however, witness Maness is incorrect in his view of the appropriate accounting outcome. He indicates, "It is appropriate to state that the actual costs capitalized by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property." Tr. Vol. 22, pp. 77-78 (emphasis added.) It is less than clear what witness Maness means by this qualification.

However, as witness Doss testified, in ARO accounting, "Under both GAAP and FERC guidance the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired." Tr. Vol. 12, p. 71 (emphasis added.) Accordingly, such costs <u>are</u> used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. As witness Doss concluded, "The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." <u>Id.</u> at 73.

When the coal ash basins at issue in this matter were constructed, they were capital assets "used and useful" in the provision of service to customers – their function was to store coal ash, a byproduct of the generation of electricity. Even if closed as a result of CAMA and the CCR Rule, the basins at all but high priority sites will remain, although they may be capped in place or have other remedial measures taken to comply with the current regulatory requirements. As such, they will remain used and useful, because they will still store coal ash, a byproduct of electricity generation. The basins at high priority sites will no longer exist, but in the case of Dan River, a new landfill is being constructed, which is a capital asset and used and useful – it, too, will store coal ash. The landfill will have a long-lived synthetic liner, a cost that even outside the concept of ARO accounting is not an "expense." Other expenses of a more O&M or general administration variety were incurred yet deferred under the deferral orders of this Commission, meaning that the Company is afforded the opportunity to recover them in rates at a later time. The funds used to pay for those costs were furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible "deferral and amortization and for earning on the unamortized balance." The Commission so orders in this case.

The question to be decided is the amount of the funds so eligible. That depends upon the Commission's analysis of the reasonableness and prudence of the costs incurred.

5. <u>Procedure for Establishing the Deferral</u>

The AGO, in its brief, argues that establishment of the ARO is unlawful on several grounds. The AGO argues that the 2015-2017 CCR remediation costs accounted for in the ARO if recovered through rates constitute retroactive ratemaking. The AGO argues that the deferral should not be permitted because DEC failed to obtain prior approval. The AGO argues that deferral of the CCR remediation costs does not meet the test established by the Commission because DEC has not shown that its earnings would have been sufficiently harmed when the ARO was established.

As to the assertion of retroactive ratemaking, the fundamental purpose of creating a deferral is to recognize that the costs were not being recovered in rates when incurred. Moreover, the test period in this case is the 12 months ending December 31, 2016 adjusted for known and measurable charges through December 31, 2017. Consequently, many of the costs are within the test period as adjusted. As to the 2015 costs, the Commission determines they along with subsequently incurred costs have been properly deferred for recovery in this case, were extraordinary when incurred, and were not being recovered in rates in effect at the time incurred. DEC notified the Commission of its decision to establish the ARO in December 2015 and sought permission to defer in December 2016. The AGO commented on the DEC request and did not object to the timing of the request.

The Commission customarily requires contemporaneous approval of deferral accounting for extraordinary expenditures incurred between general rate cases. The Commission prefers this procedure over efforts to recover pre-test year costs recovery in the general rate case where no contemporaneous approval had been sought. This is not a case where DEC failed to seek contemporaneous approval. DEC sought deferral in 2016 after giving earlier notification in 2015. It was in 2016 that the Company had information permitting a quantification of the costs at issue. Just as a utility cannot request prior approval of extraordinary storm damage costs before the storm occurs, no requirement exists of pre-event approval of CCR costs such as these - only reasonably contemporaneous approval, and the Commission has waived even this requirement in the past. See Order Granting General Rate Increase, (Dec. 21, 2012), Docket No. E-22 Sub 479, addressing DNCP's request for deferral of costs of the Bear Garden generating plant. Significantly, any AGO complaint as to timing of the deferral request should have been raised at the time DEC sought approval of the deferral. The AGO made no such complaint.

Similarly the AGO's argument that the deferral should be disallowed because DEC's earnings in 2015 and 2016 were such that deferral was unjustified should have been made at the time the deferral was sought. Moreover, the AGO's untimely evidence to support its theory of lack of economic harm to justify deferral is deficient. The AGO has referred to surveillance reports showing what DEC was earning in 2015 and 2016. These are returns that do not reflect the CCR remediation costs. DEC's December 21, 2015 notification of ARO accounting and its surveillance reports expressly state that the ARO costs are not reflected. Without showing what the returns would have been without deferral, the surveillance report returns tell little about the financial justification for the deferral. Moreover, 2016 is a test year. Financial data fully adjusted after general rate case changes should be used if looking backward at what DEC's earnings were in 2016. The Commission determines that the CCR remediation in the ARO were properly deferred and that the costs so deferred are appropriately amortized over five years and that the unamortized portion is eligible for a return.

6. The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. 1988 DEP Rate Order, p. 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and based on that analysis presented three discrete and specific proposed sets of disallowances. Two were presented through witness Junis: first, $2,109,406 of legal expenses associated with the defense of litigation matters regarding alleged environmental violations and, second, $2,352,429 reflecting groundwater extraction and treatment costs that witness Junis asserted exceed what CAMA would have required absent alleged environmental violations. Finally, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $97,698,274 relating to the cost of the Company's compliance activities at Buck, Dan River, Riverbend, and W.S. Lee, on the grounds that those activities were more costly than other reasonable alternatives.

a. Junis: Alleged Environmental "Violations"

The Public Staff, through witness Junis, asserts that disallowance of the Company's litigation expense and groundwater costs is justified because these costs flow from "violations" of the law. Tr. Vol. 26, pp. 728-34. For the reasons discussed below, the Commission based on its assessment of the evidence and in the exercise of its discretion determines not to authorize the Public Staff's proposed disallowances of legal expense and groundwater extraction and treatment costs. The evidence does not support a finding that DEC violated the law (with the exception of the federal plea agreement, the costs related to which are not at issue here), nor does it support a finding of imprudence with respect to these costs.

i. Junis: Legal Expenses

Witness Junis cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. Witness Junis suggests that the same rationale would apply to his exclusion of the Company's litigation expense related to what he terms DEC's failure to comply with environmental laws and regulations. He claims that "compelling evidence" of such violations is shown by the SOCs and DEQ reports of exceedances. Tr. Vol. 26, pp. 728-29.

The distinction between this case and Glendale Water is that, with the exception of the federal plea agreement with respect to the Dan River spill and Riverbend (for which the Company is not seeking to recover any costs of penalties and fines), there is no finding in the other litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. No Intervenor introduced evidence in this case that any "violation" actually occurred. Witness Junis' testimony that the Company's legal expenses for state litigation of coal ash complaints resulted from "violations" is based on the DEQ reports of groundwater exceedances and the fact that DEC sought SOCs to address seeps at the Allen, Marshall, and Rogers (Cliffside) stations, both of which Junis interprets as "compelling evidence of DEC's violations." Tr. Vol. 26, pp. 730-31.

The Commission determines that the facts of this case are distinguishable from Glendale Water. Litigants settle disputed matters frequently for many reasons that are unrelated to the settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes a rate of return on equity of 9.9% (versus the Public Staff's recommendation of 9.1%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This settlement, which the Commission has approved, therefore results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff somehow ceased to believe in that pre-settlement position. It means that the Public Staff, on balance, determines that its constituency (the using and consuming public) is better off with the Partial Settlement than without, despite the fact that the rate of return on equity and capital structure provisions of the settlement will cause increased rates. Likewise, an SOC is a regulatory mechanism intended to provide clarity and certainty with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. The Company's willingness to enter into an SOC, therefore, is not premised upon an underlying admission of culpability. Furthermore, as explained by witness Wells, a DEQ report of an exceedance does not equate to a violation of environmental law or regulation.

Witness Junis has attempted to expand the applicability of Glendale Water by applying its holding beyond a litigated finding of liability to include (1) resolutions of complaints that do not involve any finding of liability and (2) pending legal claims of environmental violations, where there is "compelling evidence of environmental violations." Tr. Vol. 26, pp. 729-30. The Commission disagrees with the Public Staff position. Glendale Water applies where there is a finding of liability and the Commission declines to extend its holding further. In addition, the Commission does not find DEQ exceedance reports or SOCs to constitute compelling evidence of environmental violations.

The Commission determines, as it did in the 2018 DEP Rate Order, that entering into a settlement does not equate to an admission of guilt or wrongdoing. 2018 DEP Rate Order, p. 180. Conflating the existence of a settlement agreement or an SOC with an admission or other proof of guilt or wrongdoing is inconsistent with both the law and public policy of North Carolina. The North Carolina Rules of Evidence, for example, prohibit parties from using the existence of a settlement as evidence of liability.[73] Likewise, in

[73] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

other matters before the Commission, the Public Staff has defended the regulatory policy of encouraging reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. Tr. Vol. 12, p. 156-34; see also Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar. 1, 2017) (Settlements Order). The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

Tr. Vol. 12, p. 156-35. <u>See</u> <u>also</u> Settlements Order, p. 3.

Further, in its opposition to NC WARN's petition, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation. Tr. Vol. 12, p. 156-35. <u>See also</u> Settlements Order, p. 3 (<u>citing Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A.</u>, 131 N.C. App. 257, 262, 506 S.E.2d 728, 731 (1998) (<u>Knight</u>)). The Public Staff relied on the principle articulated in <u>Knight</u> that North Carolina "law favors the avoidance of litigation," and a compromise made in good faith "will be sustained as not only based upon sufficient consideration <u>but upon the highest consideration of public policy as well</u>." Tr. Vol. 12, p. 156-35 (quoting <u>Knight</u>, 131 N.C. App. at 262, 506 S.E.2d at 731 (emphasis added) (internal quotations omitted)). As in the 2018 DEP Rate Order, the Commission again determines not to approve a disincentive to settle pending or future lawsuits. 2018 DEP Rate Order, p. 180. The Commission therefore rejects the Public Staff's proposed disallowance of the Company's legal.

ii. Junis: Groundwater Treatment Costs

Similar considerations apply to the groundwater extraction and treatment costs witness Junis seeks to disallow, which he characterizes as costs to remedy environmental violations that exceed what CAMA would have required absent such violations. He cites as examples of such costs those resulting from (1) the DEQ Settlement Agreement (also referred to as the Sutton Settlement), which Junis contends result in costs greater than would have been necessary to pay for CAMA compliance without violations, and (2) resolutions of lawsuits alleging environmental violations where the outcome involves remedial action that costs more than the risk classification warrants, and "compelling evidence" shows the outcome resulted from environmental violations. Tr. Vol. 26, pp. 731-32. Witness Junis applies this theory of disallowance to include the Company's expenditures for groundwater extraction and treatment at Belews Creek, made pursuant to the September 2015 Sutton Settlement between DEQ, DEC, and DEP. <u>See</u> Junis Exhibit 29, Official Exhibits Vol. 26 (DEQ Settlement Agreement). He also applies this theory to include the Company's expenditures for selenium removal equipment at the Riverbend plant. Tr. Vol. 26, pp. 733-34.

Consistent with the 2018 DEP Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. See DEQ Settlement Agreement, at 3, 4-5. The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina …." Id. at 3-4. Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain actions, the Commission determines as it did in the 2018 DEP Rate Order (see 2018 DEP Rate Order, p. 181) that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation.

The Commission finds the testimony of Company witnesses Wells and Kerin to be instructive with respect to the Public Staff's proposed disallowance of groundwater treatment costs, and entitled to substantial weight. Witness Wells' testimony demonstrates that DEC has in most instances adequately managed its coal ash and that the Company's management and appropriate responses to seeps and groundwater issues do not equate to environmental violations. Witness Kerin's testimony demonstrates that costs related to groundwater extraction and treatment at Belews Creek and its purchase of wastewater treatment equipment at Riverbend were reasonable and prudent and are recoverable.

Witness Wells testified that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. He explained that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified further that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built, and noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He stated that as requirements changed over time, DEC has taken action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. As he noted, witness Junis did not contend that either DEC or the state of North Carolina was an outlier by using unlined basins during this timeframe, and no such contention could reasonably be made given well-published facts about coal power generation practices at that time. Tr. Vol. 24, pp. 227-29, 233, 236, 258.

Witness Wells adequately rebutted the Public Staff's suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He testified that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, in contravention of witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. Tr. Vol. 24, pp. 244-45.

Witness Wells contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and escalating penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as an additional assessment prior to corrective action is conducted. He testified that the 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 245-46. The Commission agrees.

The Commission is further persuaded by witness Wells' testimony that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." It would be more accurate to say, he explained, that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-41, 260-61. The Commission notes in particular witness Wells' testimony at the hearing that the iterative (and difficult) nature of monitoring groundwater impacts is illustrated by the fact that two wells located a short distance from each other could present very different conditions, including different naturally occurring constituents. Tr. Vol. 26, pp. 91-93.

Witness Wells also persuasively argued that the groundwater extraction and treatment costs that witness Junis recommended for disallowance relate to activity that DEC agreed to undertake pursuant to the DEQ Settlement Agreement to accelerate, but that would have been required in the normal course as part of the groundwater correct action under the CCR Rule and CAMA. Tr. Vol. 24, p. 241. Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards.[74] In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission is also persuaded by the evidence presented by Company witness Kerin in response to the Public Staff's position, which shows that the groundwater treatment wells installed at Belews Creek would have been installed even without the DEQ Settlement Agreement, because while the time frame for that installation was moved

[74] Id.; see also N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

up pursuant to the Agreement, the Company would have installed the wells in order to comply with CAMA even absent the Agreement. Tr. Vol. 24, p. 117.

Based on the credible and persuasive testimony of the Company's witnesses, the Commission determines, with exceptions addressed below, that there is insufficient evidence that DEC would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule. Witness Wells' testimony in particular shows that the assertion that DEC's "violations" resulted in the DEQ Settlement Agreement and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence.

The Commission determines that Witness Kerin also successfully rebutted witness Junis' position that the cost of equipment to remove selenium at Riverbend should be disallowed. He explained that it was imperative for the Company to have a system to appropriately treat the site wastewater and to meet future permit selenium limits. He also noted that while this system is important for those reasons, because it is also expensive to operate, the Company will only use it when other physical and chemical extraction methods are insufficient. He emphasized the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations if selenium levels increased and no bioreactor was on site. He noted that such a delay would cost the Company millions of dollars of delay charges. Tr. Vol. 24, pp. 90, 117-19, 132. The Commission agrees that it was reasonable and prudent for the Company to purchase the bioreactor system to mitigate against potential violations of permit limits and declines to accept witness Junis' recommended disallowance of these costs.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates. The dispute relates instead to the fact that the groundwater assessment and treatment costs were incurred pursuant to a settlement with DEQ and in response to DEQ reports. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $2,352,429 – were reasonably and prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore are recoverable in rates, as are the $2,109,406 in legal fees that witness Junis also proposed excluding.

The AGO, Sierra Club, and other Intervenors make similar arguments to the Public Staff that DEC has failed to keep pace with industry standards and should therefore not be allowed to recover current environmental compliance costs in rates. As in the DEP case, these Intervenors argue that the Company should have done more, in contradiction to other witnesses that DEC should have done less, than just comply with the current environmental regulations at the time.

As an initial matter, based upon the evidence presented in this case, with the exception of the federal criminal case to which DEC pled guilty, the Company has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO witness asserts that the Commission should consider all of the seeps located at DEC's ash basin sites and deny recovery of CCR costs except – as clarified at the hearing – those which are incurred to comply with the CCR Rule. However, as stated in the criminal case that covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014, whether seeps should be covered by the NPDES permit. AG-Kerin Direct Cross Examination Exhibit 6, pp. 78, 95; AG-Kerin Direct Cross Examination Exhibit 5, p. 44. According to statements made in the criminal case, DEQ has currently not made a determination on this issue. AG-Kerin Direct Cross Examination Exhibit 5, p. 44.

In addition, the Commission finds the testimony of Company witness Kerin informative as to Intervenors' claims. Witness Kerin explained that the securities filings cited by AGO witness Wittliff simply notified the SEC of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject; they were not intended to analyze the Company's coal ash management practices and do not support any claim that such practices were out of step with industry, much less that DEC was aware of any such inconsistency. Witness Kerin also rebutted the AGO's assertion that the Company should have built new lined impoundments rather than expand existing unlined impoundments, citing the significant expense that new lined impoundments would entail, while not eliminating the obligation to maintain existing unlined impoundments. He pointed out that such action would have put the Company at risk of disallowance of costs. He recalled witness Wittliff's testimony in the DEP proceeding that utilities continued to use unlined wet ash impoundments because the law continued to allow them to do so, and noted the inconsistency between admitting that such a practice was legal and asserting that it was also imprudent. Witness Kerin also enumerated the ways in which the Company has practiced dam safety and explained that the five-year dam safety inspections demonstrate careful monitoring of issues as well as a lack of any major issue threatening dam integrity. Tr. Vol. 24, pp. 119-24. For many of the same reasons, witness Kerin demonstrated the inaccuracy of Sierra Club witness Quarles' assertions regarding the consistency of the Company's coal ash management practices with industry standards and the costs of lined landfills as opposed to surface impoundments. Tr. Vol. 24, p. 91.

The limitations of the Intervenors' and the Public Staff's approach is the fact that the kinds of actions they appear to have favored – such as lining ash ponds when others in the industry were not lining them, or creating dry ash basins when the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have increased costs that would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. These parties advance inconsistent positions. They fault the Company for not undertaking steps that others were not, but at the same time disavow any responsibility of paying for that which they – in 20/20 hindsight – wish the Company had undertaken. As noted at the hearing during questioning of Company witness Wells, these parties criticize the Company's coal ash management practices dating back decades, yet took no actions themselves to address coal ash until within the past five years. For all of these reasons and based on the evidence presented, the Commission is not persuaded, with exceptions noted below and later in this the order, that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case.

The AGO and the Sierra Club further assert that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to N.C. Gen. Stat. § 62-133.13. The Commission rejects the AGO and Sierra Club's reading of N.C. Gen. Stat. § 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEC is incurring the costs to comply with the federal CCR rule and CAMA.

Lastly, with respect to the bottled water expense DEC is seeking cost recovery of, although no party requested a specific disallowance for the cost of bottled water, the Commission finds that DEC shall remove from its request for recovery any costs for bottled water.[75]

b. Garrett and Moore: Overview

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently and unreasonably with respect to the management of CCRs from the Buck, Dan River, Riverbend, and W.S. Lee Plants, and contends that the Company should have selected different management approaches, thereby saving costs. The Public Staff recommends that a $10,612,592 disallowance be applied with regard to Buck Plant ash (Tr. Vol. 21, p. 61), a $59,320,890 disallowance be applied with regard to the Dan River Plant ash (Tr. Vol. 21, p. 67), a $489,600 disallowance be applied to Riverbend Plant ash (Tr. Vol. 21, p. 74), and that a $27,275,192 disallowance be applied with regard to W.S. Lee ash (Tr. Vol. 21, pp. 34-34), for a total recommended disallowance of $97,698,274.

The Commission determines not to accept this discrete disallowance, based upon the testimony of Company witness Kerin, which the Commission credits and to which the Commission attaches substantial weight. In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. See, e.g., 1988 DEP Rate Order, p. 29. The Commission does not question the bona fides or expertise of Garrett and Moore. The Commission is persuaded, however, by witness Kerin's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that

[75] The total amount spent on bottled water through the end of August 2017 is $1,606,185. These costs include the bottled water itself, the delivery company and personnel associated with the delivery, and the consulting firm that is managing the overall bottled water delivery program for Duke Energy. Tr. Vol. 14, pp. 220-21.

their discrete disallowances are therefore unwarranted. Witness Kerin's testimony regarding the Company's decisions is entitled to substantial weight – more weight than after the fact evaluations from Garrett and Moore. Witnesses Garrett and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. The Commission determines their recommendations deficient on the basis of a lack of credibility. In this regard, the Commission is not persuaded to discount witness Kerin's testimony by witness Wittliff's challenges to witness Kerin's expertise. As concluded in the 2018 DEP Rate Order, witness Kerin has "lived" this project since its inception (2018 DEP Rate Order, p. 187), and demonstrated competent understanding of the subject in pre-filed testimony and at the hearing. Witness Witliff's testimony from the witness stand likewise suffered from a lack of credibility.

i. Moore: Location of On-Site Landfill at Dan River

Witness Moore asserted that, while he agreed with DEC's decision to construct an on-site landfill at Dan River, he disagreed with the Company's chosen location for the onsite landfill. Tr. Vol. 21, pp. 90-91. Instead of locating the landfill within the footprint of the Ash Fill areas – which required first excavating and transporting off-site ash from those area – witness Moore contended that DEC should have considered locating the landfill along the western property boundary of the site, Id. at 91-92, even though he conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. Tr. Vol. 24, p. 94. Witness Kerin's rebuttal testimony demonstrates that witness Moore's proposal was not feasible in the time frames available to the Company, and in likelihood impossible from an engineering perspective.

Witness Moore illustrated his proposed landfill site location with a chalk-line, ovaloid drawn on top of an existing jurisdiction water designation map for the Dan River Plant. Tr. Vol. 21, p. 44; Moore Direct Exhibit 4. This drawing is the totality of the engineering work papers and documentation offered in support of his proposal in his direct testimony. Tr. Vol. 21, p. 92. To agree with witness Moore's recommended disallowance, the Commission would have to conclude that DEC should and could have constructed his proposed landfill in compliance with North Carolina law. The Commission cannot reach that conclusion based on the dearth of supporting documentation from witness Moore regarding his proposed landfill, as well as the volume of evidence presented by witness Kerin in opposition to witness Moore's suggestion. An alternative proposed action must have been feasible in order to be a valid alternative. 1988 DEP Rate Order, p. 15.

Witness Moore admitted that he did not conduct a site suitability study for his proposed landfill location, nor did he conduct a hydrogeologic study of the conditions at the western portion of the Dan River Plant property. Both studies are required under North Carolina law before a landfill can be permitted or constructed. See 15A N.C. Admin. Code 13B §§ .0503-.0504. He did not analyze soil borings of that area of the property, did not visit the portion of the property where he proposed siting the landfill, despite having the opportunity to do so when he made a site visit to the property, and did not make an attempt, at the time he submitted his direct testimony, to calculate the height of his proposed landfill. Tr. Vol. 21, pp. 92-93. Witness Moore only did this after witness Kerin filed his testimony. Tr. Vol. 22, p. 26. His testimony and workpapers, or lack thereof, would not satisfy North Carolina's landfill permit application requirements, let alone justify construction of his landfill.

The Commission concludes that DEC engineers reached the reasonable and prudent decision to reject the western portion of the property as a feasible location for an onsite landfill. As witness Kerin discussed in his rebuttal testimony, there are many engineering and other obstacles to the construction of an onsite landfill along that portion of the property.

First, construction of witness Moore's proposed landfill would have required excavation of an LCID Landfill containing asbestos. The fact that the LCID Landfill contained asbestos was not known to witness Moore when he filed his testimony, but could have been discovered had he pulled the publicly available permit for that landfill. Tr. Vol. 21, pp. 97-99. In his direct testimony, witness Moore suggested that the LCID Landfill could have been excavated and transported to the Rockingham County Landfill. As the Rockingham County Landfill no longer accepts asbestos, witness Moore conceded that his proposal with regard to the LCID Landfill was no longer possible. Tr. Vol. 21, p. 99. Even if there was a location that could accept the materials containing asbestos in the LCID Landfill, the Commission is persuaded by witness Kerin's testimony that it was prudent for the Company to avoid unnecessarily exposing workers or neighbors to asbestos by locating the onsite landfill in a location that would have required excavation of the asbestos. Tr. Vol. 24, pp. 97-98.

Witness Moore's proposal was also infeasible in that it would have significant wetland and stream impacts as compared to the minimal impacts to streams and wetlands posed by the Company's chosen onsite landfill location. Witness Moore's testimony gave too little attention to stream and wetland impacts, suggesting that mitigation of on-site streams is not uncommon to allow for construction of landfills. Tr. Vol. 21, p. 65. However, witness Moore made no attempt in his testimony to identify the stream and wetland impacts, to prepare a permitting timeline for those impacts, or to analyze the likelihood that those impacts could be permitted. As witness Kerin stated in his rebuttal testimony, and witness Moore acknowledged during live testimony, the U.S. Army Corps of Engineers (Army Corps) will conduct an alternatives analysis demonstrating the practicality of other options that would not impact streams or wetlands, and that permit applicants are required to avoid and minimize aquatic resource impacts to the maximum extent practicable. Tr. Vol. 21, pp. 104-05; DEC-Garrett and Moore Cross Ex. 1, Tab 6; Tr. Vol. 24, pp. 98-100. As compared to witness Moore's proposal, the Company's selected landfill location avoided and minimized impacts to onsite streams and wetlands. Therefore, permitting witness Moore's selected location for stream and wetland impacts would have been challenging based on the Army Corps' alternative analysis criteria. In order to meet CAMA's deadlines, it was reasonable and prudent for DEC to avoid the permitting uncertainty created by witness Moore's proposal by avoiding impacts altogether.

Witness Moore's proposal raises additional permitting uncertainties. Witness Kerin testified that the stream combination on the western and southern sides of witness Moore's proposed landfill would have required the Company to obtain a new construction permit to construct an industrial NPDES outfall through the service water pond, and that both the permit and the outfall would have required substantial time to obtain and construct. Both the new permit and outfall would have to be in place before construction on the landfill could begin, potentially jeopardizing compliance with CAMA's deadlines. The CAMA deadlines provide the overarching framework by which prudency must be assessed. 2018 DEP Rate Order, p. 185. In addition, witness Kerin noted that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02. Witness Moore did not dispute these conclusions.

The evidence shows that had witness Moore visited the site of his proposed landfill, he would have confronted dramatic elevation changes and other topographical features, such as steep slopes, that would have made his proposed site difficult. Further, had witness Moore conducted a site suitability or hydrogeologic study, he would have discovered that the depth to bedrock on the western portion of the property is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. While witness Moore agreed that a landfill owner should minimize potential impacts to neighbors, wetlands, and dangerous materials as much as possible, (Tr. Vol. 21, p. 108), the above site-specific conditions unique to the western property boundary, which witness Moore did not consider in his analysis, would have resulted in a landfill that was in the neighbors' line of sight and more intrusive than the Company's selected location. Tr. Vol. 24, pp. 100-02.

DEC's decision to minimize impacts to neighboring properties in siting its onsite landfill was consistent with an agreement that the Company would ultimately reach with the City of Eden regarding the Dan River site. As a condition of allowing DEC to construct an onsite landfill, the City of Eden required that the landfill be located near the existing basins, and as remote from residential areas as feasible. Tr. Vol. 21, p. 106; DEC-Garrett and Moore Cross Ex. 1, Tab 7. Witness Moore did not dispute the City of Eden agreement's conditions. Tr. Vol. 21, p. 107-08. The nearest location to the existing basins is within the footprint of the former ash stack, and this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. In contrast, as witness Moore acknowledged, his selected location was not closest to existing basins or as remote as feasible from residential areas. Id. Therefore, had DEC selected witness Moore's proposed landfill location, Mr. Kerin testified, the City of Eden likely would not have approved the zoning required to construct the landfill in this location. See 15A N.C. Admin. Code 13B § .0504(1)(e) (requiring local government approval for construction of a landfill). Witness Kerin stated that, if witness Moore had considered the

City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96. The Commission agrees.

Infeasible options do not support a finding of imprudence. 1988 DEP Rate Order, p. 15. Witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Dan River site were in fact reasonable and prudent, and the costs were prudently incurred. The Commission therefore rejects the Public Staff's proposed disallowance of these costs.

ii. Moore: Buck as Beneficiation Site

Witness Moore contended that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and recommended disallowance of beneficiation costs of $10,612,592 incurred within the test period at Buck. The Commission rejects witness Moore's discrete recommendation. Witness Kerin's testimony shows that witness Moore's analysis is based on a faulty interpretation of CAMA, and that DEC's selection of Buck was reasonable and prudent because it satisfies market demands and maximizes capital investment in the required beneficiation equipment.

CAMA requires the Company to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) "enter into a binding agreement for the <u>installation</u> and <u>operation</u> of an ash beneficiation project at each site capable of annually <u>processing</u> 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites." N.C. Gen. Stat. § 130A-309-216 (emphasis added). Witness Kerin testified that DEC satisfied CAMA's requirements by identifying Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

At each of the three sites, the Company has contracted to install and operate STAR technology units to process the onsite ash. Tr. Vol. 21, p. 112. The Company has also contracted to sell 230,000 tons of ash from Weatherspoon as aggregate in the manufacture of cement. <u>Id.</u> at 59, 116; Tr. Vol. 24, p. 107.

Witness Moore suggests that the Company could have selected Weatherspoon as a beneficiation site if it had only found a buyer for another 70,000 tons of ash from this location to qualify under CAMA. By selecting Buck, witness Moore contended, Duke Energy supplied an additional 300,000 tons per year of CCR material to the concrete industry, in turn reducing the demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. While the Company agrees that reuse of ash at Weatherspoon is appropriate – and the Company is selling Weatherspoon ash for reuse today – it contends that the Weatherspoon ash would not satisfy CAMA. Based on the testimony of witness Kerin, the Commission agrees.

Contrary to Public Staff witness Moore's suggestions otherwise (Tr. Vol. 21, pp. 111-12), the Commission concludes that the most reasonable reading of N.C. Gen. Stat. § 130A-309-216 indicates that the General Assembly intended that Duke Energy install and operate technology, such as carbon burn-out plants and STAR technology, to process and transform ash to a usable product rather than use the basic drying and screening methods occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07. It is here where witness Moore's theory becomes problematic.

Witness Moore's testimony suggested that the Company's handling of Weatherspoon ash, which does not involve beneficiation processing or much of any processing beyond excavation, would satisfy the CAMA beneficiation requirement. At the hearing, however, witness Moore admitted that the DEP sites chosen for beneficiation under CAMA – Cape Fear and H.F. Lee – and the DEC site, Buck, have and will use the STAR technology to beneficiate ash, and that the ash being sold from the Company's Weatherspoon site is not being beneficiated with STAR technology. He confirmed that installation of a STAR facility to convert ash for cementitious purposes is a reasonable and prudent method of executing the requirements of CAMA, and that ash from the ponds is run through the STAR unit and burned to lower the carbon content of the ash. The process changes the physical and chemical characteristics of the ash, thereby creating a stronger product that can be used in the ready-mix market. Tr. Vol. 21, pp. 111-13, 115; DEC-Garrett and Moore Cross Ex. 1, Tab 12, p. 6. As witness Moore agreed on cross examination, the Weatherspoon ash and the ash that is beneficiated with such technology, as at Buck, are "apples and oranges." Id. at 117.

Witness Moore did not object to Duke Energy's beneficiation approach at H.F. Lee and Cape Fear. Having concluded that installing STAR units at H.F. Lee and Cape Fear was a reasonable and prudent "method of executing the requirements of CAMA," (Id. at 113), the Commission determines that he cannot creditably argue that Duke Energy could have simply excavated, dried, and sold ash from Weatherspoon and still satisfied CAMA's beneficial reuse requirements. Id. at 112. In other words, witness Moore admitted that STAR units accomplish the following: "the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products." N.C. Gen. Stat. § 130A-309-216. His recommended disallowance, however, in this rate case, depends on a reading of CAMA that does not require installation of a STAR unit or similar technology. The Commission determines that the Public Staff position is inconsistent. The Commission concludes that CAMA contemplates the installation of STAR units or other ash processing technology that changes the physical and chemical characteristics of ash to specifications appropriate for cementitious products.

In addition, witness Kerin pointed out that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons. Tr. Vol. 24, pp. 105-06. Witness Moore made no attempt to identify a potential buyer for the 70,000 tons. Tr. Vol. 21, pp. 118-19. While the Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, the processed ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Id. at 105-06. The Commission determines that finding a buyer for 70,000 tons of ash from Weatherspoon would not solve the compliance problem witness Moore identifies. Under his proposal, none of the ash would be processed through a STAR Unit or similar technology, and would therefore not meet CAMA's beneficiation requirement.

The Commission also agrees with the Company that, because CAMA requires the installation of a STAR Unit or similar technology, a cost of approximately $181 million, it was reasonable for the Company to consider the amount of ash available at the site and the potential uses for the ash when making a decision to invest in beneficiation at a particular location. Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, so the per-ton cost to process ash at Buck is significantly lower than it would be at Weatherspoon. Additionally, Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. Because trucking the ash is part of the cost of the sales, Buck's proximity to Charlotte and Greensboro makes it a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia).

Witness Moore's proposal is not feasible as it would not satisfy the Company's statutory requirement to beneficiate ash. Alternative proposed actions must be feasible in order to truly be alternatives. 1988 DEP Rate Order, p. 15. The Commission cannot, therefore, conclude that the Company was unreasonable or imprudent by selecting Buck over Weatherspoon, and by implementing a beneficiation plan at Buck that does satisfy CAMA.

iii. Moore: Riverbend Off-site Transportation Costs

Public Staff Witness Moore took no exception to DEC's overall ash management plan at Riverbend, including its decision to remove CCR material from the ash stack area or the cinder pit, even though those units are not subject to CAMA or CCR. He did object to DEC's decision to transport and dispose of CCR material from the ash stack to the R&B landfill in Homer, Georgia and to the Brickhaven Facility. Witness Moore recommended that the Commission disallow $489,000 as the premium that was paid to dispose of CCR material from the Ash Stack at the R&B Landfill in Homer, Georgia versus the Marshall Station. Tr. Vol. 21, pp. 72-73.

As witness Kerin noted in his testimony, DEC was required to begin excavation of ash from Riverbend within 60 days of receiving its stormwater permit from DEQ. When DEC received that permit in May 2015, Marshall was not available to accept Riverbend ash. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015 to begin excavating Riverbend ash. While the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet DEQ's deadline, and thus it was imperative that the Company contract with a company to haul and dispose of the

Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015. While DEC eventually received approval to dispose of Riverbend ash at Marshall, the Commission is persuaded that DEC would not have been able to send ash to Marshall within the time frames required by DEQ. Tr. Vol. 21, pp. 93, 108-10, 131-32.

Witness Moore's recommended disallowance is based on a "perfect world" scenario where DEC could have accurately predicted permitting uncertainties, such as the dates when DEQ was going to issue the stormwater permit for Riverbend or approval for ash disposal at Marshall. The Commission declines to approve disallowances where the Company promptly achieved compliance with DEQ's 60-day excavation requirement. The Commission uses the CAMA deadlines as the framework by which to assess prudency. 2018 DEP Rate Order, p. 185. The Commission concurs with witness Moore that "[t]he lowest cost option may not always be the reasonable or prudent decision. The determination must be made on a case-by-case basis and the specific factors, obligations, site-specific limitations and other factors known by management at the time." Tr. Vol. 21, pp. 89-90. The Commission concludes that the Company acted reasonably and prudently for the Company to begin excavation at Riverbend as soon as practicable in order to ensure compliance with DEQ's requirements. This decision necessitated finding a temporary disposal solution; therefore, the costs associated with that temporary disposal solution are also reasonable and prudent and should not be disallowed.

iv. Garrett: W.S. Lee Off-site Transportation Costs

The Commission is not persuaded by witness Garrett's testimony that a lower cost option at W.S. Lee was feasible. Like witness Moore's recommended onsite landfill at Dan River, witness Garrett's proposal for W.S. Lee may look viable on paper, but when applied to "real world" conditions, it loses its persuasiveness.

As an initial matter, the Commission agrees with the Company and witness Garrett that DEC's overall ash management plan at W.S. Lee, which includes building an onsite landfill to store ash from the Primary and Secondary ash basins, is reasonable and prudent. Tr. Vol. 21, pp. 25-26. The Commission also agrees that some action was necessary to excavate the IAB or Old Ash Fill to mitigate risk associated with the long-term environmental issues, based on the proximity of the IAB to the Saluda River. The Commission declines to accept, however, witness Garrett's conclusion that delaying excavation of those sites for seven years would have been acceptable to South Carolina regulators or would have eliminated the risk to the Saluda River. Tr. Vol. 24, p. 156.

No dispute exists that DEC's decision to excavate the IAB and Old Ash Fill before the onsite landfill was complete eliminated the geotechnical and environmental risks by November 2017. Tr. Vol. 21, p. 28. Under witness Garrett's plan, ash in the IAB and in the Old Ash Fill would have been left in place and not excavated until the on-site landfill in the secondary ash basin was complete in 2022. Tr. Vol. 21, pp. 129, 130-31. Therefore, the ash would have remained in the IAB and Old Ash Fill an additional seven years until

2022 as compared to the excavation plan DEC undertook. Tr. Vol. 21, pp. 127, 131-32. Under the Company's agreement with SCDHEC, which required excavation of the IAB and Old Ash Fill by December 31, 2017, witness Garrett's seven-year delay was not an option. Tr. Vol. 24, p. 151.

Even assuming witness Garrett's plan was technically feasible and would have resolved the stability issues, implementing his plan would have required trading old risks for new risks. See DEC-Garrett and Moore Cross Ex. 1, Tab 20. Witness Garrett acknowledged during live testimony that the report contained at Tab 20 concluded that if the IAB ash was not removed, danger arose of it's flowing into the Saluda River. Tr. Vol. 21, pp. 135-36. He also acknowledged that in certain areas of the IAB that abut the Saluda River, the steep, 1:1 slopes are covered in trees and vegetation. Id. at 137. Witness Garrett also agreed that trees would have to be removed to execute his proposal, but he did not consider in his analysis how the trees would be removed (with heavy equipment or chain saws) or how tree removal might affect slope stability. Id. at 148-49. He also acknowledged that soft, alluvial clays run beneath the IAB and the steep slopes where his proposed work would occur, and that the dam itself is partially constructed from ash and sandy silt that would also have to be excavated. Id. at 138, 141. Witness Garrett conceded that his work proposal as reflected in Garrett Direct Exhibit 3 is "not a design document" nor is it "specific instruction on how to go about that work." Id. at 141. He also acknowledged the limitations of the S&ME report on which he relies, in that it, too, does not explain practically how a slope stability and grading project would be executed. Id. at 141, 146-47.

The Company provided persuasive evidence in the form of witness Kerin's testimony that witness Garrett's proposed grading and stability project would not have been reasonable or prudent. Witness Kerin testified that the equipment necessary to implement witness Garrett's proposal could not have safely traversed the dike on the downslope of the IAB. Moving the heavy equipment to the downstream/river side of the downslope to excavate silt, ash, sand and trees would have created undue risk to bank stability, worker safety, and risk of an ash release into the Saluda River. Witness Garrett's proposed project would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. These new risks were understandably unacceptable to the Company. Tr. Vol. 24, pp. 112-14, 132.

The Commission cannot conclude that witness Garrett's proposal was the more reasonable and prudent option because the Public Staff cannot show, from an engineering perspective, how the work would be practically and safely executed. The Public Staff only presented a concept. To take witness Garrett's plan from concept to reality would require engineering and design plans with specific instructions on how the work would be conducted. Tr. Vol. 21, p. 141. The Public Staff, although armed with an engineering expert, failed to present any such plans. On the other hand, Company witness Kerin credibly provided evidence of the real-world flaws with witness Garrett's concept, from both timing and engineering perspectives.

The Commission concludes that it was reasonable and prudent for Duke Energy to immediately excavate the IAB and Old Ash Fill, in compliance with its agreement with SCDHEC. Duke Energy was able to eliminate existing risks without creating new risks. The Commission declines to second-guess the Company's judgment in that regard. Therefore, because no onsite landfill was available for the disposal of the IAB and Old Ash Fill materials at the time they were excavated, it was also reasonable and prudent for the Company to utilize the R&B landfill in Homer, Georgia for disposal of those materials, and the costs associated with that effort should not be disallowed.

Finally, based on witness Kerin's testimony the Commission agrees that the Company's plan to mitigate future risk of operating two ash management structures, which would be the result if it did not excavate the Structural Fill Area at W.S. Lee in the future, is reasonable and prudent, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

7. <u>Conclusion with respect to January 1, 2015 – December 31, 2017 Costs</u>

The Commission finds that the costs are known and measurable, were reasonably and prudently incurred, and to the extent capital in nature are used and useful in the provision of service to customers. The Commission determines the costs were properly deferred. As such, with the exception noted below, they are recoverable from customers. The issue that remains is the amortization period over which this recovery is to be made.

The Commission deems the Company's proposal, which submits that the amortization period should be five years, to be reasonable and appropriate. The Public Staff, in its 51/49 "equitable sharing" proposal, suggests a period of 25 years (with no return), but its suggestion is tied to (indeed, mathematically required by) the sharing arrangement. As discussed more fully above, the Commission determines that the Public Staff's sharing proposal is from the Commission's perspective arbitrary and unfairly punitive and therefore unacceptable. Thus, a 25-year, no return amortization period is not approved. The five-year period suggested by the Company is identical to the period over which the Commission approved in the 2018 DEP Rate Case, as well as the period over which Dominion North Carolina Power's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case (Docket No. E-22, Sub 532). Further, inasmuch as the Company appropriately applied ARO accounting and this Commission's deferral orders issued in Docket No. E-7, Sub 723 to these costs, the Company is eligible to earn a return.

In summary, with the exception noted below, DEC has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from January 1, 2015 through December 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) where capital in nature used and useful, and, as such, those costs are recoverable in rates. DEC has further shown that its proposal that these costs be amortized over five years, with a modified return on the unamortized balance, is reasonable. The Commission encourages the selection of minority and women-owned businesses, where appropriate, when contracting for future services associated with compliance with CAMA and the CCR Rule.

8. The Commission's Cost of Service Penalty

The costs DEC has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEC initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEC's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent most of the leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEC for failure to undertake this remediation process years earlier before being required to do so. The evidence shows that DEC undertook steps toward CCR remediation and incurred costs in anticipation of impending closure but hesitated to spend substantial sums until the requirements became clearer. Had DEC acted in compliance with assertions that it act more aggressively sooner, it would have incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEC should have acted differently in the past or what the increased costs would have been then. The Commission rejects efforts from any source to advance theories in support of discrete disallowances that parties before the Commission have not seen and have therefore been denied any opportunity to analyze and respond. The Commission must depend on parties before it, particularly the Pubic Staff, with the statutory responsibility to audit and respond to general rate case filings to advance theories for cost recovery.

Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEC would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts. Had DEC acted irresponsibly in neglecting seeps earlier, the remedy would have been pumping the water from the seeps back into the basin, for example. Costs of this remediation would have been negligible in comparison to removing ash or cap-in-place.

DEC in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEC through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEC acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEC risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan. Even today efforts to soften the impact of the EPA CCR Rule are under consideration by the current administration. If effectuated, anticipated cost recovery may change in the future.

A significant example of the ambiguity and uncertainty DEC faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County referred to in the 2018 DEP order. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> 1983 Pond is Unlined
>
> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils.[76] This pond has been functionally full since 1983, but is still permitted[77], and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future.[78] There is also a county well water source approximately 1200' from the test well that is monitored by the county.
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> Elsewhere in the report under the "Do Nothing" alternative, the author stated: It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined

[76] The reference to "native sandy soils" is significant. Its characterization for absorption of leachates is greater than for the clay soils of the Piedmont at issue with respect to the DEC impoundments in this case.

[77] The 1983 impoundment operated pursuant to a DEQ permit. Obviously, at the date of the report, DEQ was not requiring closure or dewatering and removal of the CCRs. This would not occur until passage of the CCR Rule and CAMA years later.

[78] This recitation is consistent with the comprehensive testimony of witness Wells in this case that with respect to the types of contaminants at issue from CCR impoundments, they exist in naturally occurring quantities in the soil. Monitoring wells showing exceedances above standards are not dispositive without measurement of naturally occurring constituents.

starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations." The author of the report does not elaborate or explain. Were the Commission to attempt to read the author's mind, this would be mere speculation. To the extent DEQ was enforcing them, DEQ was not requiring DEC to take additional steps to comply. As the report states, the 1983 impoundment was operating pursuant to a DEQ permit, and DEQ had not required closure. The author repeatedly uses the word "assumes" and "anticipated" to predict the environmental regulators' future intent. The author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. With respect to the 1983 Sutton unlined impoundment, that impoundment will never be relined. If it had been relined as the author suggests, the Company would have been required to move the CCR's twice, once to some new location, then back to the newly relined 1983 repository. Such is not the case for compliance with EPA CCR rules and CAMA where the CCR's were moved only once -- deposited in a new, lined landfill.[79]

The EPA's CCR rule was passed in 2015, and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEC did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment in response to the report. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to the DEP case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEC incurred to meet CAMA deadlines, such as at Dan River, Riverbend, or Buck, before all of the regulatory requirements had been finalized. A substantial area of contention is

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[79] Intervenors are highly critical of DEC for failure to take action in response to consultants, in-house investigative teams and outside research entities such as EPRI before 2015. However, quite inconsistently, when it comes to criticizing DEC's actions after 2015, they assert that DEC was remiss in not stopping short of what SCDHEC wished for remediation of W.S. Lee and the consultant for the selenium treatment at Riverbend. They contend DEC spent too much in complying with these required or suggested remediation steps.

exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. As testified to by witness Wells, with respect to covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014 whether seeps should be covered by the NPDES permit. Even as DEC continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the Mountain Energy Act of 2015, changing the requirements for the Asheville plant remediation for DEP. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the selection of repositories for beneficiation. Intervenors contend DEC spent too much to comply with CAMA. As discussed below, others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEC's impoundments and prohibit cap-in-place and spend more than DEC contemplates irrespective of what DEQ may require. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

Intervenors maintain that DEC should have addressed CCR remediation in years prior to EPA's CCR regulations and CAMA when the industry began to grow concerned over potential CCR environmental degradation. Under this theory, remediation costs would have been lower then and as a consequence CCR remediation costs DEC seeks for recovery beginning in 2015 are excessive and should be disallowed in whole or in part.

The most significant shortcoming in this theory is that no attempt has been made by any party to this case to demonstrate what the costs would have been in earlier years that theoretically would be so much lower as to make the 2015 and subsequent CCR remediation costs unnecessary or excessive. To the extent efforts are made in this case after the record has closed, as was the case in the DEP case, DEC has had no opportunity to respond and any such effort is unfair and inappropriate.

Before EPA CCR rules and CAMA, DEC's impoundments were operated under permits authorized and overseen by DEQ or its predecessor, clients of the AGO. DEQ suggested no requirements that DEQ dewater the impoundments, remove the CCRs and transport them to lined landfills or install caps in place. No requirements existed for DEC to follow. Had DEC undertaken impoundment closure, DEQ would have been required to oversee the process, but of what that oversight would have consisted is unknowable today.

DEC has incurred costs beginning in 2015 and thereafter pursuant to elaborate EPA and CAMA requirements under close scrutiny and oversight from DEQ. Parties to this case hotly contest and dispute the steps DEC has taken to comply and assert that DEC's expenditures have been unreasonable.

In an effort to comply with CAMA, DEC identified Buck as a beneficiation site. Public Staff witness Moore argues DEC should have chosen instead Weatherspoon and that DEC therefore spent $10,612,592 too much between January 1, 2015 and November 30, 2017.

In order to comply with CAMA, DEC constructed an onsite landfill of Dan River. Public Staff witness Moore argues that DEC selected the wrong site, the former footprint of the Ash Fill 1, and should not have increased the costs to transport CCR materials offsite. He contends that DEC spent $59,320,890 too much.

In order to comply with CAMA, DEC transported CCRs from the Riverbend Ash Stack to the R&B landfill in Homer, Georgia and to the Brickhaven facility. Public Staff witness Moore contends that the material should have been disposed of at the Marshall plant and DEC spent $489,600 too much.

In order to comply with SCDHEC requirements, DEC attempted to close the regulated ash basin of W.S. Lee and mitigate risks of the unregulated inactive ash basin and fill area. Public Staff witness Garrett disagreed with DEC's decision to immediately begin excavation and transportation from these basins and transport CCRs to the R&B landfill in Homer, Georgia. Witness Garrett testified that DEC spent $27,275,192 too much.

Public Staff witnesses contend that DEC spent $97,698,274 too much to comply with EPA and CAMA. Even with access to steps DEC took and to the compilation of costs DEC incurred, these witnesses encountered difficulty understanding what DEC did. Witness Moore calculated the cost for excavating, transporting and disposing of Ash Stack I at the Dan River off-site to be $83,531,985. This was $3.8 million too high because this amount should have been attributable to excavation and transportation of ash from the Primary Ash Basin. The cost to build the alternative landfill location when accounting for the need to address asbestos and relocate the warehouse building at Dan River increases witness Moore’s cost determination by $10,790,900. Witness Moore originally included costs of parcels at Cliffside even though DEC had not requested recovery of those costs. Witness Moore assumed DEC began transport of CCRs from Riverbend to the R&B Landfill beginning May 2015 and continuing to February 2016. However, the DEC contract with Waste Management was for 17 weeks through September 18, 2015.

Witness Moore criticizes DEC for spending too much at Buck, Riverbend, and Dan River <u>to comply with</u> CAMA requirements. Witness Junis criticizes DEC for spending too much at Belews Creek and Riverbend for remediation <u>not required by CAMA</u> for selenium removal. Witness Quarles criticizes DEC for <u>spending too little</u> at Allen and Marshall to remediate by not removing the coal ash from the unlined basins there in disregard of what DEQ <u>may ultimately require for compliance with CAMA</u>. The Commission deems the various Intervenor theories for remediation cost disallowance “all over the map” and deficiently inconsistent.

With so much disagreement over what DEC should have done or is doing to comply with EPA requirements and CAMA, the Commission determines that insurmountable obstacles exist to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory. The Public Staff, the agency required by statute to audit rate requests and recommend adjustments, candidly testified that it does not base its recommended equitable sharing recommendations on past DEC imprudence. That agency was unwilling to attempt to speculate what DEC should have done in the past, when it should have acted and, most significantly, what the costs would have been. No other party has undertaken such effort. Without any evidence sponsored by any witness quantifying what DEC should have spent in the past, the Commission has no basis for disallowing 2015-2017 DEC remediation costs in support of a theory that DEC should have done more prior to 2015.

The Commission would be required to anticipate the difficulty in complying with local ordinances like the ordinance DEC confronted from the City of Danville. The Commission would be required to anticipate the level of community opposition such as that experienced at Riverbend. The Commission would be required to anticipate what, if any, issues the legislature or DEQ might have imposed for beneficiation. The Commission would be required to anticipate the reaction of state or local representatives to DEC’s decision to excavate or cap-in-place repositories within their legislative districts. The Commission concludes such tasks are unwarranted.

Intervenor theory on groundwater exceedances is that DEC violates 2L standards whenever monitoring wells show exceedance of standards or where DEC has not installed monitoring wells in addition to those required by DEQ to disprove the existence of exceedances. Some of the exceedances were from measurements taken within the CCR impoundments. The Commission cannot accept this theory. The fallacy of the theory rests on the fact that the undisputed evidence is that all of the constituent elements measured against the standards, including iron, manganese and pH, constituents harmful neither to the environment nor human health, occur naturally in the North Carolina soils irrespective of the proximity of coal ash impoundments. The evidence shows that DEQ by its actions or inactions does not agree that the existence of exceedances without evidence that they are caused by coal ash contamination pose a risk to the environment or human health so as to require immediate remediation. DEQ has established a low priority to DEC's request to add 2L limits to NPDES permits. Although the Commission is not an environmental regulator, it must agree with DEC and DEQ that failure to take the costly actions required to comport with this Intervenor theory falls well short of mismanagement so as to justify some unquantified disallowance of 2015-2017 costs of dewatering and removal of CCRs from unlined pits or construct caps, which will cure exceedances caused by CCR groundwater contamination, if any.

This Commission’s responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission’s responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation and beneficiation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess specific DEC decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEC for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

In his testimony, AGO witness Wittliff asserts that DEC's mismanagement caused CAMA and that costs DEC incurred to comply with CAMA in excess of those to comply with EPA CCR requirements should be disallowed. Witness Wittliff makes no effort to quantify the disallowance he proposes under this theory. In contradiction of its own witness, the AGO in its post-hearing brief argues that all of DEC's 205-2017 CCR remediation costs should be disallowed -- again without showing what DEC's costs should have been before 2015 under the AGO's theory. The AGO insists it is up to DEC to make these calculations for it.

Aside from the unsubstantiated theoretical underpinnings of the Wittliff argument, it is not possible to segregate CAMA 2015-2017 costs from EPA CCR costs. Indeed, a major prudency disallowance advocated by the Public Staff addresses 2015-2017 remediation costs at DEC's W.S. Lee plant in South Carolina. DEC was required to meet deadlines beyond those imposed by the EPA but not as a result of CAMA, which did not apply outside of North Carolina.

Conversely, the Commission is unable to find DEC faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEC's mismanagement of CCRs "caused" the General Assembly to enact CAMA. DEC argues that other nearby states enacted CCR remediation statutes in addition to EPA's CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA's requirements. The Commission is unable to conclude that DEC mismanagement is the primary cause of CAMA. Just as a preamble never accepted cannot legally justify legislative intent, neither can the absence from earlier versions of CAMA that would have addressed cost recovery. Nevertheless, the provisions of CAMA directly address remediation of DEC CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEC mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEC witness Wright's testimony suggests as much. While DEC presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEC represented that it mismanaged its CCR activities.

The Commission's conclusions with respect to the impact of DEC's mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty in the form of cost disallowance arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Buck, Riverbend and Dan River transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEC's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified. Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEC admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEC's mismanagement of its CCR activities, neither can it state that DEC activities were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEC has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEC has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEC pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. N.C. Gen. Stat. § 62-2(a)(5). Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, N.C. Gen. Stat. § 62-2(a)(6). All companies are prevented from violating environmental statutes. N.C. Gen. Stat. § 143-215.1. DEC is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal-fired generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEC's irresponsible management of its impoundments over a discrete period of time placed its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEC cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEC pled guilty was only for a fraction of the time DEC operated the impoundments. No evidence was submitted that DEC's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall wellbeing of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEC incurred with respect to discrete remediation activities.[80] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Cliffside, Riverbend and Dan River disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEC advocates, unjustified. The Commission deems the Public Staff's 51/49 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. N.C. Gen. Stat. § 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co.,

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[80] As the Commission recited in its order in the DEP case, AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> ... I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. Tr. Vol. 15, pp. 77-78.

The same evidentiary shortcoming is present in the record in this case.

285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[81] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEC's mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs. As the penalty is a defined monetary penalty rather than a percentage return penalty, the impact on cost of service would be the same if it had been a rate of return on rate base penalty.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $70 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. As the Commission has addressed comprehensively above in this order, the Commission possesses the discretion to authorize a return on the unamortized balance. The unamortized balance is not a recurring test year operating expense. The annual amortization of the balance (return of not return on) is the amount that equals to operating expense pursuant to N.C. Gen. Stat. § 62-133(b)(3). The penalty will be imposed by reducing the resulting annual revenue requirement by $14 million (from the return on the unamortized balance on the capitalized costs) for each of the five years, resulting in an approximate $70 million management penalty. While this penalty differs in form from that in General Telephone, the Commission determines that conceptually General Telephone provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEC actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEC will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEC concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR

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[81] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction …").

remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEC's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery. Prior to the next rate case, the Commission shall require that DEC provide a detailed accounting of its Cost of Removal Reserve for its steam assets and how the Company is utilizing this Cost of Removal Reserve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence supporting this finding and conclusions is contained in the Company’s verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Public Staff witness Maness stated that coal ash costs prudently incurred from 2015 through 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. Tr. Vol. 22, pp. 63-64. He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Junis. Id. Witness Junis testified that environmental lawsuits had not been resolved for several DEC plants. Tr. Vol. 26, p. 732.

Witness Wright argued against witness Maness’ recommendation of provisional cost recovery. Witness Wright stated that provisional rates appeared to be retroactive ratemaking and the utility should not be subject to hindsight review. Tr. Vol. 12, errata pp. 156-39-40.

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEC’s CCR costs that are approved in this Order. The Commission has weighed the Public Staff’s and other intervenors’ concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEC amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEC has committed that insurance proceeds recovered by DEC will benefit ratepayers as an off-set to DEC’s CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEC must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

DEC has used a demand allocation factor to allocate its costs related to its compliance with state and federal environmental regulations regarding coal ash pond closures in this case. Tr. Vol. 19, p. 39. Additionally, the Company has identified specific CAMA-related costs and allocated these costs directly to North Carolina customers. Tr. Vol. 6, p. 314.

Public Staff witness Maness recommended applying a jurisdictional allocation of all coal ash expenditures by a comprehensive system factor. Tr. Vol. 22, pp. 66-68. He stated that his adjustment removed the distinction between costs DEC described as CAMA-only and the remainder of the coal ash costs. Id. at 66. He stated that for CAMA-only costs, DEC utilized North Carolina retail allocation factors that do not allocate any of the system level costs to South Carolina retail operations. Id. at 67. He opined that even though some of the costs incurred by DEC are being incurred pursuant to North Carolina law, it is fair and reasonable to allocate those costs to the entire system because the coal plants associated with the costs are being, or were, operated to serve the entire DEC system. Id. Public Staff witness Maness also stated that he used the energy allocation factor to allocate system-level coal ash costs to North Carolina retail operations, rather than the demand-related production plant allocation factor utilized by the Company. Id. at 67-68. Witness Maness recommended that an energy allocator be used to determine the North Carolina retail portion of the coal ash costs because they are being incurred due to the fact that the coal ash was produced by the burning of coal to produce energy over the years, and like the cost of coal, should be allocated by energy, and not peak demand. Id. at 68.

NCSEA witness Barnes also objected to DEC's classification of coal ash costs as demand related. He argued that this approach is contrary to cost causation principles because coal ash is a by-product of consumption of a fuel, and the volume of coal ash produced is associated with overall energy use, not demand during a single hour of the year. He recommended that all coal ash remediation costs approved for recovery be allocated using an energy allocator. Tr. Vol. 20, p. 62.

Additionally, CIGFUR III witness Phillips testified in support of the Company's proposed allocation of coal ash management costs on a demand basis, stating that such allocation "is appropriate and should be approved." Tr. Vol. 26, p. 258. CIGFUR III witness Phillips further testified that coal ash is not a fuel, but an environmental waste with no energy potential. Id. at 271. Witness Phillips also stated that compliance costs associated with coal ash remediation did not exist at the time the coal was burned, but arose more recently. Id. Therefore, remediation costs should not be allocated on a kilowatt-hour basis. Id. Further, the investment associated with coal ash ponds is typically included in generation plant accounts and should be allocated on the same basis and DEC allocates generation plant based on demand. Id.

In her rebuttal testimony, DEC witness McManeus opposed witnesses Maness' recommendation that the costs DEC identified as "CAMA only" be allocated to all jurisdictions, instead of directly assigning these costs to North Carolina. Tr. Vol. 6, p. 313. Witness McManeus explained that while she generally agrees that the costs of a system should be borne by all of the users of the system, the Company has identified very specific cost categories that should be treated as an exception to this general rule due to their nature as being unique to North Carolina. Id. These cost categories include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to CAMA. Tr. Vol. 14, p. 120. Witness McManeus explained that this allocation is consistent with prior Commission decisions related to the Company's costs of complying with other North Carolina laws including REPS and the North Carolina Clean Smokestacks rule. Tr. Vol. 6, pp. 313-14. Because the Commission has allowed the Company to recover 100% of its costs associated with complying with those North Carolina laws, the Company believes it is also appropriate that CAMA-specific costs be directly assigned to North Carolina customers. Id. at 314.

Additionally, Company witness Hager responded to witnesses Maness' and Barnes' recommendation to classify coal ash costs as demand related. Witness Hager explained that the costs in question are associated with compliance with federal and state environmental requirements related to closing coal ash ponds. Tr. Vol. 19, p. 39. Residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand. Id. This is supported by the fact that end of life costs (removal costs) and salvage values are factored into depreciation rates, and depreciation expenses are allocated based on demand. Id. Witness Hager also noted that it is also consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs which are allocated based on demand. Id. at 39-40.

The Commission finds and concludes, with respect to the above-stated adjustments, that it is appropriate to (1) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to the South Carolina retail; and (2) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor. Regarding the jurisdictional allocation, the Company had directly assigned costs for certain groundwater wells and permanent water supplies to North Carolina on the grounds that such costs were mandated by CAMA and were unique to North Carolina. Tr. Vol. 6, pp. 259, 313-14; Tr. Vol. 14, p. 134. In contrast, witness Maness argued the coal plants had served the entire North Carolina and South Carolina system of DEC, so the costs should be allocated across both jurisdictions. Tr. Vol. 22, pp. 66-67. Regarding the allocation factor, the Company recommended the demand-related factor (Tr. Vol. 6 p. 314; Tr. Vol. 19, pp 39-40), whereas the Public Staff argued for the energy-related factor because the amount of coal ash is related to the amount of energy produced. Tr. Vol. 22, pp. 67-68. The Commission agrees with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy. Accordingly, and consistent with the Commission's February 23, 2018, Order in Docket No. E-2, Sub 1142, the Commission finds and concludes that the deferred coal ash costs should be allocated across the entire DEC system, and should be allocated on the energy-related factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-78

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On February 26, 2018, the AGO filed a Stipulation as to Admission of Evidence. The AGO and DEC stipulated that the testimony given by Company witness David Fountain regarding insurance coverage in Docket No. E-2, Sub 1142 (DEP Rate Case), along with the associated exhibits, is appropriate to be admitted into evidence in the present case. The testimony was located in the DEP Rate Case in Volume 7 of the transcript in pages 368 through 505 and AGO Fountain Cross Examination Exhibits 1 through 8.

In its post hearing brief, the AGO requested that the Commission monitor the insurance litigation and contended that it would be appropriate for the Commission to make similar findings and conclusions regarding insurance that it made recently in the DEP Rate Order.

The Commission concludes that DEC should be required to place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case.

The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts. A deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DEC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-82

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company presented Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues reflecting DEC's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement riders. Per those exhibits, the resulting proposed revenue requirement increase of the Company is $372,527,000. Boswell Corrected Third Supplemental and Stipulation Exhibit 1, Schedule 1 shows the Public Staff's revised recommended incorporating the provisions of the Stipulation, the impact of the EDIT decrement riders and its adjustments reflecting the Public Staff's position on the unresolved issues. The resulting proposed revenue requirement adjustment by the Public Staff is ($385,697,000).

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEC recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEC work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEC and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to N.C. Gen. Stat. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See N.C. Gen. Stat. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEC's individual customers, as well as to the communities and businesses served by DEC. DEC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C. Gen. Stat. § 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEC and the Public Staff on February 28, 2018, is hereby approved in its entirety.

2. That the Lighting Settlement entered into by DEC and NCLM, Concord, Kings Mountain, and Durham, is hereby approved in its entirety.

3. That DEC shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public

Staff to verify the accuracy of the filing. DEC shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEC and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

4. That DEC is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 3.

5. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEC and verified by the Public Staff as soon as practicable.

6. That the appropriate revenue requirement for the first four years shall be reduced by the annual State EDIT rider decrement of $60,102,000.

7. That it is appropriate to recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate in DEC's base rates.

8. That DEC's proposed $200 million per year credit metric mitigation measure is denied.

9. That DEC shall continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

10. That DEC's request to establish a rider to recover Power Forward costs is denied.

11. That DEC's request, as an alternative to a rider, to establish a regulatory asset for the deferral of Power Forward costs is denied.

12. That DEC is instructed to collaborate with the intervening parties, through the generic and DEC-specific Integrated Resource Planning and Smart Grid Technology

Plan docket, toward the goal of resolving some or all of the issues surrounding grid modernization and the most appropriate cost recovery mechanism for such costs.

13. That the Pilot Grid Rider Agreement and Stipulation is disapproved.

14. That the Company shall implement an increment rider, beginning on the effective date of rates in this proceeding, and expiring at the earlier of (a) May 31, 2020,[82] or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in this Order, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, and fuel adjustment riders.

15. That on or before March 31, 2019, the Company, in consultation with the Public Staff, shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026.

16. That the approved base fuel and fuel-related cost factors (excluding regulatory fee), by customer class, are as follows: 1.7828 cents per kWh for the Residential class, 1.9163 cents per kWh for the General Service/Lighting class, and 2.0207 cents per kWh for the Industrial class.

17. That the Company is hereby, authorized to establish a regulatory asset for deferral of post in-service costs for Lee CC, as described herein. These costs shall be amortized over a four-year period.

18. That DEC's request to cancel the Lee Nuclear Project is granted.

19. That DEC's request to recover its project development costs relating to the Lee Nuclear Project is granted, with the exception of costs relating to the Visitors Center and the 2018 AFUDC, as described herein.

20. That the balance of Lee Nuclear Project development costs, adjusted to remove land costs, shall be moved from CWIP Account 107 to regulatory asset Account 182.2 and amortized over a 12-year period, and that the Company shall not earn a return on the unamortized balance.

21. That the Public Staff's proposal that the Company be required to refund to customers $29 million per year relating to the Company's NDTF is hereby, denied.

22. That the depreciation rates proposed by DEC in this case, as modified by this order, are approved.

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[82] The Company may request an extension of the May 31, 2020 date.

23. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

24. That the Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES and ESA) to $14.00. The BFC for other rate schedules shall remain unchanged.

25. That the Company is hereby authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. The regulatory asset account shall accrue AFUDC until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner. At that point, the costs will be amortized over 15 years.

26. That DEC shall file reports regarding the development, spending, and accomplishments of the Customer Connect project each year by February 15 for the next five years or until the Customer Connect project is fully implemented, whichever occurs later. Further, DEC and the Public Staff shall develop the reporting format for the annual Customer Connect project report and file the format with the Commission within 90 days of this Order.

27. That DEC shall prepare and file a lead-lag study in its next general rate case.

28. That DEC's request to recover its AMI costs of $90.9 million in this proceeding is hereby approved.

29. That within six months of the date of this Order, DEC shall file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy.

30. That DEC's costs for AMR meters replaced by AMI shall be recovered over a 15-year period.

31. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

32. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

33. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

34. That with respect to the Company's vegetation management program, the Company shall eliminate the 13,467 miles of Existing Backlog, as described herein, within five years after the date rates go into effect in this proceeding.

35. That any accelerated amount of expenditures to eliminate the Existing Backlog shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor increases.

36. That DEC shall provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog.

37. That the proposed amendments to DEC's Service Regulations are hereby approved.

38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

39. That DEC shall file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

40. That DEC's proposal to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule is approved.

41. That DEC shall recover the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, in the amount of $545.7 million, to be adjusted based on the allocation factors to be provided by DEC and the Public Staff pursuant to Ordering Paragraph No. 3, and DEC is authorized to establish a regulatory asset as requested in the Company's petition in Docket No. E-7, Sub 1110. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

42. That DEC shall not be allowed to recover on an ongoing basis $201.3 million in annual coal ash basin closure costs, subject to true-up in future rate cases. DEC is authorized to record its January 1, 2018 and future CCR costs in a deferred account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

43. That within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC. This reporting requirement shall apply even if the case is appealed to a higher court.

44. That DEC shall place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

45. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

46. That the Commission's approval in the Order for deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

47. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEC shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and the schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

48. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate adjustment by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt, Deputy Clerk

Commissioner ToNola D. Brown-Bland concurring in part and dissenting in part.

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

As to a very large number of the myriad issues decided in the Commission's Order in these consolidated cases, I concur in the results reached by the majority. On four topics, however, I would reach different outcomes, and I write separately here to explain my dissent. To summarize my differences from the majority:

I. I would disallow recovery of $244,433,678[1] from the expenditures made by the Company during 2015, 2016, and 2017, related to closure of waste coal ash storage facilities at the Company's eight coal-fired generating plants and for permanent disposal of the waste ash from those facilities, on the grounds that these amounts, in some instances, represent expenditures that were imprudently incurred and, in other instances, represent amounts that the Company imprudently failed to recover in prior rates.

II. For all allowed costs incurred during the period 2015 through 2017, as to the closure of the waste ash storage units and disposal of the ash, I would allow deferral and recovery amortized over a period of five years, but without allowance of any rate of return on the unamortized balance. I would so decide on the grounds that, as to some of such costs, allowance of a rate of return is not authorized by law and, as to all of such costs, the record presented in this case does not and cannot support allowance of a return as a matter of Commission discretion.

III. I would not authorize any increase in the fixed monthly charge (the so-called "basic facilities charge" or "BFC") imposed on residential rate classes on the grounds that there is no evidence in the record to support any such increase.

IV. I would permit the Company to defer to a regulatory asset account its costs for deployment of AMI meters, without a carrying charge, on the grounds that the record as it now stands cannot support a finding that this investment is reasonable or prudent.

In the following sections, I discuss the evidence and rationale for these conclusions in more detail.

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[1] This total, as with the other amounts discussed in this section, are systemwide numbers and do not represent the North Carolina retail allocation. The data presented by the Company on waste ash expenditures were all on a systemwide basis.

I. Cost Recovery for Permanent Closure of Waste Coal Ash Facilities

A. General Matters

I start with a truism – each case stands upon its own merit and its own facts. This case follows hard on the heels of the proceeding in Docket No. E-2, Sub 1142 (DEP Rate Case), the general rate case of the Company's affiliate, Duke Energy Progress, LLC (DEP), decided by Commission Order dated February 23, 2018 (DEP Rate Case Order). For issues centering on the storage and disposal of wastes[2] from the burning of coal to generate electricity, the two cases are intimately linked, both factually and legally, but the evidentiary presentation in the two cases was not identical. It is because of the differences that I begin my dissent in this case in the same manner as I began my dissent in the DEP Rate Case[3] with a brief commentary on the state of the evidentiary record.

The evidence presented in this case, and most especially the documentary record that speaks to historical industry practices and standards, and to the Company's own internal policies and practices relating to the management of coal ash wastes, is considerably better developed than it was in the DEP Rate Case. This is largely due to the efforts of the Public Staff and several of the intervenor parties, most especially the Attorney General's Office (AGO). In some instances the new or additional evidentiary materials are pertinent not only to adjudication of the Company's request in this case, but also speak directly to factual issues that were in play in the DEP Rate Case. Sometimes the additional evidence in this case presents issues not considered at all in the DEP Rate Case or opens lines of inquiry not identified in that case. Many documents are dated after the time the Company and DEP became affiliated entities, and they address plant decommissioning and ash basin closure plans, activities, and costs for DEP facilities as well as for the Company's plants. Since these documents were not introduced as part of the record in the DEP Rate Case, they could not form the basis for any of the findings of fact or conclusions of law in DEP Rate Case.

As noted, the differences between this case and the DEP Rate Case are largely manifested in the presentations by the Public Staff and by intervenors. On the other hand, the Company's evidentiary presentation in this case largely mirrored and followed DEP's approach in the DEP Rate Case, an approach I have found less than satisfactory in both cases.[4] The Company depends on the evidence of witnesses whose testimony is very often of questionable value, largely because they lacked pertinent knowledge or

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[2] These are euphemistically called sometimes "coal combustion residuals," or "CCRs," for shorthand reference. Because I think this manner of speaking tends to obscure, rather than to clarify the topic, I will continue to call them "wastes," which is in fact what they are.

[3] DEP Rate Case Order at pp. 248-278.

[4] As an initial matter, it is worth a reminder that the Company alone has the burden of proving its case-in-chief when it elects to file an application requesting a rate increase through a general rate case. It is not required of, nor would it be appropriate for, the Commission, the Public Staff, or any other intervening parties to fill in the gaps of any lacking evidence which may be necessary to substantiate the Company's *prima facie* case.

experience of the matters about which they testified, and expressed opinions and conclusions for which they had insufficient foundation. With very limited exceptions, *all* of the evidence in the record for the time prior to 2014 concerning (1) industry standards and practices relative to the management of coal ash wastes, (2) the Company's history of management of coal ash wastes, and (3) the pertinent regulatory requirements relating to coal ash wastes exist in this record only in the form of documents and exhibits offered by the Public Staff or by various other intervenors, or in the form of late-filed exhibits filed by the Company in response to specific questions and requests for information made by members of the Commission, on the record, during the evidentiary hearing. The Company's primary witness on these matters, witness Kerin, only first assumed responsibility for the Company's response to coal ash issues in 2014, without any pertinent prior experience concerning the subject. Notwithstanding this, he testified: "I'm the witness on coal ash for the Company." Tr. Vol. 24, p. 167. Although he testified that he had reviewed various historical documents and Company records as part of his introduction to his new duties, on a number of occasions during the evidentiary hearing, he was confronted with significant historical Company or industry documentation which was altogether unfamiliar to him or which he could not recall well enough to discuss. See, e.g., Tr. Vol. 14, pp. 252-271; Tr. Vol. 15, pp. 12-121. His conclusory testimony that the Company had complied with all pertinent laws and regulations, and had conformed to industry standards prior to 2014, simply cannot be afforded any substantial weight.[5] Company witness Wells, whose experience dated from 2009, displayed a better knowledge of the historical documentary record, but his own experience was limited to environmental compliance matters and did not extend to ash basin design, construction, operation, maintenance, or management issues, or to planning and cost recovery for closure of ash surface impoundments. The Company provided no witness who could testify concerning the Company's budgeting for, accounting for, or recovery of costs

[5] The majority seeks to buttress witness Kerin's credibility concerning historical matters by referring to the peer group of regional utility companies which witness Kerin convened and participated in since having assumed his current role in 2014, and points to the knowledge he has gained from those peer companies about past practices concerning coal ash wastes. Under cross-examination, however, witness Kerin admitted that the principal purpose of his peer group was to discuss forward-looking issues relating to implementation of the EPA's CCR Rule and related post-CCR Rule regulations at the state level. He also acknowledged that in response to a discovery request submitted by the AGO, he had not been able to provide any significant substantive information he had learned from his peer group about historical coal ash management practices. See Tr. Vol. 15, pp. 70-75; Kerin Direct AGO Cross Ex. 9 (Ex. Vol. 16, Part 3, pp. 309-311).

Witness Kerin's knowledge of matters dating before 2014 was so deficient that at the close of cross-examination, counsel for the Attorney General moved to strike his testimony concerning industry standards and practices and the Company's own policies and practices concerning the management of coal was wastes prior to 2014. Tr. Vol. 15, pp. 76-78. The motion was denied as having been made untimely pursuant to Commission Rule 1-21(c). The motion was in fact timely made, being one which the cited rule recognizes as arising in the course of the hearing to which it relates and, therefore, exempt from the ten-day prior notice requirement. I suppose that in defense of the ruling it could be argued that the motion was actually a "dispositive" motion and therefore subject to the ten-day prior notice requirement, since excluding witness Kerin's testimony would have deprived the Company of its only witness supporting the Company's *prima facie* case on issues going to the prudence and reasonableness of the Company's management of coal ash wastes prior to 2014.

associated with the handling of coal ash wastes prior to 2014.[6] This is a matter that takes on some significance for reasons to be discussed later in Section I.C. of this dissenting opinion. Finally, Company witness Wright's testimony consisted very largely of inadmissible legal opinions concerning his interpretation of provisions of Chapter 62 of the North Carolina General Statutes, and his conclusions as to whether the legal standards therein were satisfied in this case.[7] E.g., State v. Weeks, 322 N.C. 152, 164-65, 367 S.E.2d 895, 903 (1988); State v. Ledford, 315 N.C. 599, 340 S.E.2d 309 (1986).

As already noted, the evidence presented by the Public Staff and several of the intervenors was considerably more detailed and informative in providing an understanding of the evolution of industry standards and practices relating to waste coal ash. But, as was the case in the DEP Rate Case, significant gaps opened when it came time to show how the Company's responses to those evolving standards and practices translated into excessive or avoidable costs for which recovery in this rate case should be disallowed. The presentations by most of the intervenors, and the responses and replies by the Company, centered very largely on subsidiary issues: whether exceedances of North Carolina's 2L groundwater protection standards[8] (2L Rules) are "violations of law" and thus are evidence of imprudence, whether the allowance or creation of unpermitted seeps from ash impoundments is evidence of imprudence or is instead part of the natural order of things, whether the continued use of unlined surface impoundments into the current decade was or was not imprudent, whether delays in instituting comprehensive and continuing groundwater monitoring programs at all plants was or was not imprudent, and so on. With the exception of the Public Staff the parties objecting to the Company's requested rate increase made less effort to connect these subsidiary issues to the ultimate question the Commission must decide, which I summarize as follows: did the Company mismanage its waste ash storage and disposal facilities, either generally over a period of years, or else in discrete instances, in ways that unreasonably caused it to incur costs today that it could have avoided, or that caused an unreasonable increase in the level of costs for tasks that it would have to undertake in any event? Put differently, how much, if at all, have the costs of closure of the waste coal ash facilities been increased by the Company's acts or omissions addressed in one or more of these subsidiary issues? Here, the evidence and arguments of the parties have, in my judgment, been less helpful to the Commission than I would have wished. In the

[6] As an example of this omission, I point to Fountain Direct AGO Cross Ex. 6, a document titled "Ash Basin Closure Update," dated January 13, 2014. Tr. Vol. 9, p. 100-103; Ex. Vol. 10, pp. 609-694. That document included information concerning the Company's accumulated reserves for decommissioning expenses of its coal-fired steam plants and contained some discussion about options for using these reserves to offset the costs of ash basin closures. Although his name appeared on the title page as one of the authors of the document, Company witness Fountain was unable to answer questions about this information. Later witnesses, including Company witness Doss, and the Company's third-party witnesses Spanos and Kopp, who testified concerning depreciation and decommissioning costs, were likewise unable to answer questions attempting to explore the information contained in this exhibit.

[7] See, e.g., Tr. Vol. 26, pp. 157-230.

[8] N.C. Gen. Stat. § 143-211 et seq.; 15 N.C.A.C. .02L .0101 et seq.

following discussion I have tried to undertake answering that question in a manner that is supported by the available evidence.

B. Specific Disallowances of Requested Cost Recovery

I address first the Public Staff's proposals for specific cost disallowances, which the Public Staff does attempt to link to discrete acts or omissions by the Company that are alleged to have been imprudent or unreasonable. With respect to most of those proposals, I concur in the results reached by the majority. While I disagree with the narrow reading of the Glendale Water[9] case that appears to be espoused by the majority, I agree that on the specific facts of this case, the Public Staff's proposed disallowance of legal expenses in the amount of $2,109,406 is not warranted under my own reading of Glendale Water. I leave my disagreement about interpretation of that case for another time when it may make a difference to the outcome. For the reasons set forth by the majority, I agree that (a) the Public Staff's proposed disallowance of groundwater extraction and treatment costs at Belews Creek, (b) the Public Staff's proposed disallowance of costs for equipment purchased to treat and remove selenium from waste ash at the Riverbend Plant, (c) the Public Staff's proposed disallowance of costs incurred for temporary and short-term transport of ash wastes from the Riverbend Plant for offsite disposal in Homer, Georgia, and (d) the Public Staff's proposed disallowance of costs arising from the selection of the Buck Steam Station as a beneficiation site under CAMA[10] should not be accepted, and these costs should instead be allowed as requested by the Company, subject to the general adjustment arising from matters discussed in Section I.C. hereafter.[11]

In the following Sections 1.B.(i)-(ii), I discuss my differences with the majority with respect to two items for which the Company seeks recovery of expenditures made in 2015, 2016, and 2017. In each case, I conclude that the greater weight of the evidence shows that the Company did not act in a reasonable and prudent manner. Instead, the Company elected to pursue higher cost closure activities when, based on what was known at that time, reasonable lower cost alternatives were still available. In addition, I find that these costs were incurred in direct consequence of the Company's admitted imprudence and mismanagement of its waste ash impoundments at Dan River Steam Station (Dan River Plant) and that, but for the release of waste ash into the Dan River in February, 2014, such costs could or would have been avoided.[12] Finally, in Section I.C.,

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[9] State ex rel. Utilities Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986).

[10] S.L. 2014-122.

[11] I also agree with the Commission's majority decision to disallow $1,606,185 for costs incurred to provide temporary bottled water supplies to customers, as far as it goes. However, I believe that decision should also have included the additional $1,862,898 spent by the Company through August, 2017, to provide *permanent* alternative drinking water supplies to customers in the vicinity of some of its coal-fired plants.

[12] For present purposes, I find that the Company's guilty plea to Counts One through Four (Dan River Plant) and Count One (Riverbend Plant) of the federal criminal indictment, supported by the Joint Factual Statement, sufficiently establishes that the Company was imprudent and negligent in its

I conclude that the Company has imprudently managed cost recovery for known and measurable anticipated costs for coal ash basin closures in the period prior to the present general rate case. This is an issue not adequately addressed by the majority.

(i) W.S. Lee Steam Station – Inactive Ash Basin and "Borrow Area"

The W.S. Lee Steam Station (Lee Plant) in Anderson County, South Carolina, commenced commercial operations in 1951 and was officially retired as a coal-fired plant in November 2014. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9). Two of the three existing coal units were fully retired; the other was converted to natural gas. The Company's plans for decommissioning and closure of the coal-fired units and the associated waste ash surface impoundments were part of a more comprehensive generating fleet modernization program, which is described in detail in the Company's 2012 Plant Retirement Comprehensive Program Plan. See Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839). Under that plan, retired coal-burning units were to be decommissioned and demolished to grade level, and ash ponds were to be closed using a cap-in-place strategy, with long-term monitoring thereafter.

During the period prior to retirement of the coal units, there were four waste ash storage or disposal areas at the Lee Plant. The oldest was a surface impoundment originally constructed in 1951. This impoundment was closed and a new, larger impoundment was constructed on top of the closed basin in 1959. The second impoundment was in use until 1977, when a third impoundment was constructed. The two original impoundments are sometimes referred to in the record as the "inactive ash basin," and other times as the "1951/1959 basins." E.g., DEC's Late-Filed Exhibits in Response to Commission's Request for Closure Plans (March 28, 2018). When use of the 1951/1959 basin was discontinued, the impoundments were dewatered and a soil cover was placed over the ash remaining in them. See Kerin Direct Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110); Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). The new impoundment opened in 1977 was subdivided into "primary" and "secondary" sections. Only these two components were actively receiving and storing ash waste when the coal-fired generating units at the Lee Plant were retired in 2014. In addition to the two active impoundments and the inactive ash basin, there was an area to the north of the inactive ash basin, sometimes referred to as the "ash fill area," and other times referred to as the "borrow area." Id. This area contained ash that had been excavated from the impoundments and dry stacked. Both the inactive ash basin

management of the ash impoundments at the Dan River Plant. Kerin Sierra Club Cross Exs. 6-7 (Ex. Vol. 16, Part 1, pp. 401-457). As the Company's counsel acknowledged to the Court, the violations of the Clean Water Act to which the Company pleaded guilty were essentially "negligence-based crimes." Ex. Vol. 16, Part 3, p. 235, Lines 11-12. In the present circumstances, the standards for imprudence and negligence are essentially alike. See, e.g., Hempling, Regulating Public Utility Performance, p. 237 (ABA, 2013); Arizona Pub. Serv. Corp., 21 FERC ¶63,007, p. 65,103 (1982), aff'd in relevant part, 23 FERC ¶61,419 (1983); Appeal of Conservation Law Foundation, Inc., 507 A.2d 652, 673 (N.H. 1986) (describing the prudence standard as "essentially applying an analogue of the common law negligence standard").

and the ash fill area were located on that portion of the plant site bordering the Saluda River.[13]

On April 1, 2014, in the wake of the ash release into the Dan River, Company representatives met with the South Carolina Department of Health and Environmental Control (DHEC) to discuss the status of the inactive ash basin. Interest in the inactive ash basin centered on the fact that there was a 60-inch diameter corrugated metal pipe under the inactive ash basin that had been constructed before 1951 and had been used to carry stormwater runoff from the plant site to the Saluda River, a design that was similar to the corrugated metal piping construction that had failed under the ash impoundment at the Dan River Plant. In addition to this pipe, there were two smaller pipes that had conveyed discharge water from the 1951/1959 basins to the river. None of these three pipes was in use in 2014. In the days before the April 1, 2014 meeting with DHEC, the Company had inspected the three pipes and had found no evidence of any flow in them, or any discharges from them.[14] In a letter to DHEC on April 4, 2014, following the earlier meeting, the Company advised that it planned to grout and seal the three pipes and anticipated submitting plans for this work by April 28, 2014. See Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, p. 76). It is evident that the recent Dan River ash release was much on the minds of the Company and DHEC at this time. The Company's letter stated:

> Unlike the basin at Dan River, there has not been standing water in this inactive basin for many years. The pipes are not discharging to the river, and the risk of a potential release to the Saluda River is low since little water exists in the basin.

Id.

On May 1, 2014, the Company again wrote to DHEC to provide an update and a proposed schedule for permanently plugging the three pipes. Id. at 85-86. Again, on May 8, 2014, the Company wrote to DHEC to advise on the progress of its third-party engineering contractor, Soil & Materials Engineers, Inc., and to discuss in more detail its plans for plugging the 18-inch diameter discharge pipe for the 1959 basin.[15] Id. at 91-92. The Company reported that video inspections had disclosed no evidence of water seeping into or otherwise infiltrating the piping. Further letter reports were made to DHEC

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[13] A site diagram and brief explanatory history of these ash disposal areas is contained in Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110). The summary here largely is based on that exhibit.

[14] During the course of the plea hearing in the Company's criminal case, Company counsel acknowledged that the Dan River ash release had prompted the Company to conduct inspections of all of its concrete and corrugated metal pipes at its various waste ash storage and disposal facilities. Kerin Direct AGO Cross Ex. 7, p. 72 (Ex. Vol. 16, Part 3, p. 246.)

[15] In connection with plugging the discharge pipes for the 1959 basin, the Company also planned to raise the level of the basin dike to provide additional assurance that stormwater runoff that might collect in the basin during a heavy rain event would not overtop the dike after the discharge pipes had been sealed, causing erosion of the dike.

on June 19, June 26, July 3, and on July 30, 2014. Id. at 93-110. Even though the coal-fired units at the Lee Plant were scheduled for retirement in the fall of 2014, and planning work was underway for the much larger effort required to decommission those units and the active waste ash impoundment, it was clear that in April and May, 2014, the situation involving the piping underneath and associated with the closed 1951/1959 basin, had become a central focus of attention. This interest is of significance since the inactive ash basin was not at that time subject to South Carolina's dam safety regulations or any other regulatory regime relating to waste surface impoundments. Likewise, the "ash fill" or "borrow area" was not subject to any permit requirements or to any generally applicable regulation at the time. As it turns out, the inactive ash basin was not, and is not, subject to the EPA's CCR Rule, and, of course, it is not subject to North Carolina's CAMA. I also note that there is no evidence in the record that, during this time, either the inactive ash basin or the "borrow area" were causing, or were otherwise associated with any groundwater or surface water contamination on or in any area surrounding the plant site, including the Saluda River.

Following this sequence of events, on July 17, 2014, DHEC tendered to the Company a draft consent agreement which required the Company to develop and then to implement a remedial plan for the inactive ash basin. See Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). This draft consent agreement did not specify the work to be performed by the Company nor did it establish any timetable for that work but, instead, established a procedure for DHEC review, oversight, and approval of whatever work the Company proposed to undertake. The draft stated as a conclusion of law, not supported by any findings of fact whatsoever, that a release or threat of release of hazardous substances had occurred from the inactive ash basin in violation of the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980[16], notwithstanding the fact that coal ash wastes were not themselves classified as "hazardous" for purposes of the Resource Conservation and Recovery Act,[17] or the fact that there was at that time no evidence of any contamination of soils, surface water, or groundwater that could be associated with the inactive ash basin. Id. The draft simply recited that: "Duke Energy is entering into the Consent Agreement out of concern for human health and the environment and will take all necessary steps in compliance with all environmental laws to prohibit future releases from the Site." Id. at 175.[18] Based on the structure and content of the draft agreement between DHEC and the Company and the testimony from both the Company's witnesses and from Public Staff witness Garrett, who has had extensive experience dealing with DHEC in regards to coal ash surface impoundments, I find that it is more likely than not that DHEC lacked any legal basis to impose the consent agreement in the absence of the Company's acquiescence.

[16] 42 U.S.C. §§ 9601-9675.

[17] 42 U.S.C. §§ 6901-6992k.

[18] The draft July 17, 2014 consent agreement contains no findings that there had been any *past* releases.

According to the testimony from witness Kerin, on September 29, 2014, the Company and DHEC entered into a revised consent agreement that required immediate excavation of the inactive ash basin and removal of the ash therein and, additionally, excavation and disposal of the ash in the unregulated borrow area, with all such activity to be completed by December 31, 2017.[19] Tr. Vol. 15, pp. 121-123. Throughout the period leading up to September, 2014, the evidence is clear that both the Company and DHEC were focused on the issue of the corrugated metal pipe running under the inactive ash basin and on the status of the two discharge pipes. For reasons that will be discussed presently, it is significant that the communications during this time period contain no indication that either the Company or DHEC were concerned about the structural integrity or stability of the inactive ash basin's dike. With respect to the impounding dike, all attention was focused on whether the level of the dike should be raised in order to prevent stormwater overflows after plugging of the discharge pipes.[20]

The Company's plan for closure of the active primary and secondary ash basins was to construct a new, on-site lined landfill within the footprint of the secondary basin, to dewater the ash in the basins, and then to excavate the ash and move it to the new on-site landfill. This new landfill would have sufficient capacity to accommodate not only the ash quantities in the active primary and secondary basins, but also the quantities that were contained in the inactive ash basin and the borrow area. Tr. Vol. 21, pp. 24-25. This fact is not disputed by the Company. However, because of the strict timetable established in the September 29, 2014, agreement, the Company concluded that it would be unable to wait for construction of the new on-site landfill before relocating ash from the inactive basin and the borrow area and, instead, needed immediately to excavate the unregulated, closed, inactive ash basin and the borrow area, and then to transport the wastes to an offsite third-party landfill in Homer, Georgia. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

Based on this evidence and on the testimony by witnesses Kerin and Garrett, I conclude that DHEC's and the Company's insistence on immediate excavation and removal of the ash in the inactive ash basin and in the borrow area was a direct and proximate result of the ash spill at the Company's Dan River Plant in February, 2014. I base this on the following factors, among others: (1) that both the inactive ash basin and the borrow area were unregulated, were not subject to any permit requirements or outstanding directives, and did not later become subject to the federal CCR Rule; (2) that

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[19] The revised consent agreement, executed on September 29, 2014, was not put into the record in this proceeding by any party, but I have accepted the testimony of witness Kerin as to its contents and substance. It marked a significant change from the July 17, 2014 draft consent agreement, a matter which is not further explained in the record of this proceeding.

[20] Also of interest here are Junis Exs. 14, 15 and 16 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 9-24) which are a series of communications between the Company and DHEC in the first half of 2014 concerning compliance issues relating to the two active impoundments at the Lee Plant. Among other topics discussed in the communications are the stability of the dams and embankments for the primary and secondary ash ponds and the potential for liquefaction of soils in the event of an earthquake. These communications do not discuss any issues relating to the inactive ash basin or the borrow area.

the inactive ash basin was not subject to South Carolina's dam safety law; (3) that no concern appears in the record concerning any aspect of either the integrity of the inactive basin dike, the discharge pipes, or the corrugated metal stormwater pipe under the basin until immediately after the Dan River spill; (4) that as witness Kerin testified and as the correspondence reveals, the Dan River incident and, more particularly, the risk of failure of corrugated metal piping under the basin was a specific topic of concern to DHEC and was the focus of the parties' attention in the months following the Dan River spill[21]; and (5) that DHEC initially sought to assert regulatory control over the basin through a statute clearly inapplicable to it, evidencing the pressure it was placing on the Company to address its concerns about the basin. I note that none of this history leading to the Company's agreement to commence immediate excavation of the inactive ash basin and the borrow area is discussed in the majority's analysis of this issue.

The Company, seeking to avoid a finding that the Dan River incident was the principal driver of the September 29, 2014, agreement, contends that immediate excavation and removal of the ash from the inactive ash basin was necessary in order to avoid the risks of sloughing of the impoundment dike or, more severely, liquefaction of the soils underneath the dike structure in the event of a major earthquake, and that removal of the ash from the basin would eliminate any concern about a release of ash into the Saluda River in such event. Witness Kerin testified to the point as follows:

> The S&ME report had some recommendations on how do [sic] deal with the steep slopes and how to deal with some stabilization of the dam, but if you think of liquefaction, there is no way to solve liquefaction from a dam modification issue. Liquefaction is the underlying soils below the dam. So those soils were alluvial, which is based on being beside that river over the years. You put that on top -- there was sandy soils, so our core borings indicated that the base of that dam was very susceptible to liquefaction even [sic]. So if you think of what liquefaction is, you take the sand, the ash, you shake it, it basically liquefies and it will move. So the concern here was, below that dam, the base of that dam right along the Saluda River, and that is right -- if you are familiar with that dam, the toe of that dam is on the river -- that any earthquake even or severe shaking of that would cause that earth to liquefy and you would lose the contents. Very similar to what happened in the TVA event, when their dam, the surfaces below, liquefied in Kingston.

Tr. Vol. 15, p. 118.

There are significant discrepancies between the conclusion that the Company wishes the Commission to draw about its decision in 2014 to proceed immediately to excavate the inactive ash basin and the borrow area, and the documentary evidence in the record. These discrepancies are so great that I conclude that the Company's theory is an after-the-fact rationalization, and that based on the evidence of what the Company

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[21] In particular, see Tr. Vol. 24, pp. 152-155, where witness Kerin testified that based on reports from his superior, John Elnitsky, who attended meetings with DHEC, the Dan River incident and the similar drain pipes under the Lee Plant basins were a primary focus of DHEC's concerns.

knew, did, and said at the time in 2014, its decision to commence immediate excavation and removal was not based on a concern about the structural integrity of the dike at the inactive basin in the near or intermediate term or the possibility that a seismic event would occur.[22] I summarize these discrepancies in the following itemized points:

1. In response to a pre-hearing data request to the Company submitted by the Public Staff, which requested documents upon which the Company relied in concluding that there were unacceptable risks associated with leaving ash in the inactive ash basin until such time as the new onsite landfill was completed and the ash could then be removed to that new landfill, the Company produced an engineering report and analysis by URS Corporation, dated June 30, 2015 (URS Report). <u>See</u> Garrett Duke Cross Ex. 1, Tab 20 (Ex. Vol. 22, pp. 137-232). More will be said about this report presently. For now I note only that the report proffered by the Company was dated some eight months after the Company had already entered into its September 29, 2014, consent agreement with DHEC and over a month after the Company had already begun excavating the inactive ash basin and transporting the ash offsite. The Company had already made its decision and begun to take action before the URS Report was delivered.[23]

2. The URS Report assessed not only the inactive ash basin and the borrow area, but also the two active surface impoundments. First, among the key findings in the report's executive summary were the following:

   > Imminent Dam Safety Issues: No conditions were observed or identified by analyses completed under Phase 2 that represent a dam safety condition requiring immediate attention.

   <u>Id.</u> at 143.

   Among the other key findings were that the alluvial soils and ash of the inactive basin could be susceptible to liquefaction during the maximum design event earthquake and could be unstable following such an earthquake, and this was the subject to witness Kerin's testimony, as quoted above. *This exact same finding was made in the URS Report with respect to both the active primary and secondary ash basins,* which noted that "for the primary ash pond that is near the design normal pool elevations, it is possible that portions of the pond could breach, releasing its contents." <u>Id.</u> at 209. These identical findings are significant because the Company has contended that it could not responsibly carry the seismic risk identified in the URS Report for the seven-year period

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[22] It should not escape notice that there were then, and have been since, no identified structural risks associated with the unregulated borrow area, but the Company also committed in 2014 to immediately excavate and transport for offsite disposal of the ash in the borrow area.

[23] Ex. Vol. 22, pp. 138-232.

required to construct its new onsite landfill and that, therefore, it was necessary to commence excavation and removal of ash from the unregulated inactive ash basin and the borrow area immediately. Yet the Company considered that very same risk to be acceptable with respect to the wastes that would remain in the primary and secondary ash basins until such time as the new onsite landfill was constructed and available for use, notwithstanding that the URS Report identified geotechnical stability and performance issues for the primary ash basin that were as significant as any that were identified relative to the inactive ash basin.[24]

3. The URS Report notes, on page 5, that URS had not done a more detailed analysis of the liquefaction potential for the inactive ash basin due to the fact that ash removal from the basin was already underway, rendering further analysis unnecessary.

The URS Report was preceded by a report prepared by the Company's engineering consultant, Soil & Materials Engineers, Inc. (S&ME), dated September 12, 2014 (S&ME Report), which was only a couple of weeks before the Company committed to immediate excavation and removal of ash from the inactive ash basin and the borrow area. Garrett Direct Ex. 2 (Ex. Vol. 22, pp. 6-43). This S&ME Report is not discussed by the majority in its analysis. The S&ME Report included field and laboratory testing and modelling of both slope stability of the dike and liquefaction potential of the underlying soils in the event of a major earthquake (modeled using a magnitude 7.3 on the Richter Scale, which was the magnitude of the 1886 Charleston earthquake).[25]

The S&ME Report recommended that the Company continue to monitor the basin embankments to observe and detect any changing conditions. It noted that the addition of rip rap material along the river bank would alleviate any short-term risks of surface erosion and shallow sloughing due to river flow along the base of the embankment. The S&ME Report further recommended that *if* the Company wished to improve slope stability beyond the existing case, it could undertake to buttress or to flatten the slopes of the embankment, but S&ME did not go so far as to find that the existing condition of the slope was unacceptable. In response to a data request from the Public Staff, the Company admitted that S&ME had not recommended immediate excavation of the inactive ash basin, and that it had provided specific instructions on how to undertake any *optional or elective* changes to the embankment that the Company wished to make. See DEC's

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[24] Of course, since the coal units at the Lee plant had been retired in November, 2014, the Company cannot explain this difference by pointing to a need to continue to use the primary ash basin to sluice and store new ash wastes from ongoing and future operations.

[25] The majority states that witness Garrett's proposal that the Company should have delayed excavating the inactive ash basin until the new onsite landfill was available "…would have required trading old risks for new risks." Majority Order at 309. But the "risks" considered in the S&ME Report were not new ones – they had been present since the closure of the inactive ash basin in 1977. As the S&ME Report explicitly noted, the actual historical performance of the dike was a factor to be considered in assessing whether any remedial action was required or was desirable, and that engineering standards for new dikes or impoundments were not necessarily a reliable guide for evaluating existing impoundments with an extended history of actual operation.

Response to Public Staff Data Request No. 58-22, pp. 1-5 (March 23, 2018) (filed as a late-filed exhibit pursuant to my request and the request of Commissioner Brown-Bland, which were made on the record during the evidentiary hearing).

The S&ME Report represents the state of the Company's knowledge at the time it concluded that it would commence immediate excavation and offsite disposal of the contents of the inactive basin, and there is nothing in the S&ME Report that suggests an immediate or near-term risk of any release of materials into the Saluda River while awaiting construction of the new onsite landfill.

Public Staff witness Garrett concurred in the Company's decision to excavate the inactive ash basin and remove its contents to the new onsite landfill at the time it was completed, and I do not take issue with this portion of his analysis. He disputes only the timing of the Company's decision, which necessarily required more expensive transportation and offsite disposal. The majority takes the testimony of witness Kerin, who in period April to September, 2014, was brand new to the coal ash arena and had no first-hand knowledge and minimal prior pertinent experience, at face value. I find, on the other hand, that the testimony of Public Staff witness Garrett, who had first-hand experience in a number of coal ash projects in South Carolina and had negotiated extensively with DHEC, is far more credible on the matters in dispute. <u>See</u> Tr. Vol. 21, pp. 16-17 (setting out witness Garrett's specific experience with ash impoundment closures in South Carolina).

Based on all of the foregoing, I find that the Company's decision to commit in 2014 to immediate excavation and removal of the ash in the inactive ash basin and the borrow area at the Lee Plant was a direct consequence of the atmosphere created by the Company's imprudent management of the impoundments at the Dan River Plant, and was not due to any then-existing concerns about the integrity of the embankment of the inactive basin itself. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

(ii) <u>Dan River Steam Station</u>

The three coal-fired generating units at the Dan River Steam Station (Dan River Plant) were retired in April, 2012, and the process of decommissioning the plant commenced thereafter. Associated with the coal units were two surface impoundments, known as the "primary pond" and "secondary pond," and two areas where dry waste ash had been placed, known as "fill area 1" and fill area 2," respectively. The Company had been anticipating and planning for retirement of the coal units at the Dan River Plant since at least 2008. <u>E.g.</u>, Kerin Direct Public Staff Ex. 2, Part 2, pp. 49-53 (complete copy filed in the record by Public Staff March 19, 2018, pursuant to Commission request during the evidentiary hearing).[26] Even earlier, in its 2003 Coal Combustion Ten-Year Plan (2003 Plan) the Company had planned for the management of the ash waste storage and disposal areas in order to maximize use of available land on the plant site. Kerin Direct

[26] References to this exhibit hereafter are to the complete copy of this exhibit filed by the Public Staff as a late-filed exhibit on March 19, 2018.

AGO Cross Ex. 1 (Ex. Vol. 16, Part 2, pp. 123-280). The 2003 Plan concluded that the Dan River Plant had adequate ash waste storage area for at least another twenty years in either greenfield or brownfield disposal cases. The 2003 Plan contemplated a series of measures to provide long-term capacity involving excavating ash from the surface impoundments and then stacking the excavated ash in the two ash fill areas, thereafter covering the fill areas with synthetic caps. See, e.g., Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 3, pp. 1-49). Total projected spending on these projects through 2013 was estimated to be $1,150,000 in capital costs, and approximately $5,700,000 for operating and maintenance costs.

The Company's 2008 Coal Combustion Products Ten-Year Plan (2008 Plan) continues the operating plan laid out in the 2003 Plan – periodic excavation of the two impoundments in order to preserve capacity followed by stacking the excavated ash in the two ash fill areas. The 2008 Plan noted that due to the plant's planned retirement schedule, conversion to dry ash handling and disposal, a topic considered in the 2003 Plan, would not be pursued. Kerin Direct Public Staff Ex. 2, Part 2, p. 55. At the time, the 2008 Plan contemplated that the ash fill areas would be capped with a synthetic cap and closed in 2011, and contained an estimated project budget for this activity, although it noted that the timing of that project might be re-evaluated depending on the actual plant closure date. Id., p. 142.

As far as the record discloses, when the coal units at the Dan River Plant were retired in 2012, nothing was done immediately to start the process of dewatering the two surface impoundments, notwithstanding the fact that the Company knew that dewatering was the single most important early step to be taken in order to eliminate or reduce the hydraulic pressure of the standing and interstitial water in the basin, and thereby reduce seepage and migration of ash constituents to surface water and groundwater. E.g., Tr. Vol. 15, pp. 33-74.[27] At the time of the February, 2014 ash release into the Dan River, dewatering of the impoundments still had not taken place. Nothing had been done to relieve the hydraulic pressure in the impoundments on the pipes that ran underneath them. The record discloses no external obstacle standing in the way of the Company's taking action to commence dewatering of the ash basins after 2012. The delays were all internal.

On January 22, 2014, a matter of days before the release of ash from the primary pond, the Company received a draft design report from its contractor AMEC Environment & Infrastructure, Inc. detailing the proposed closure of the surface impoundments

[27] Of interest on this point is an undated internal Company document titled "Ash Basin Closure Strategy." AGO Late- Filed Ex. 1, Tab E (filed as part of the evidentiary record on April 18, 2018, and subsequently accepted into the evidentiary record by Commissioner Order dated April 27, 2018). Internal evidence indicated that the document was most probably prepared sometime in 2013. Discussing "timing considerations" relating to ash basin closures the document notes: "[d]ewatering the ash basin in accordance with the NPDES permit will over a relatively brief time reduce and/or eliminate seepage which the company is currently addressing." Id. Addressing the Court at the sentencing hearing in the Company's criminal case, Company counsel stated: "The thing about seeps is that the easiest way to control a seep is to let us dry out the coal ash and move it and close those basins." Ex. Vol. 16, Part 3, p. 253.

(January 2014 AMEC Plan). Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 1, pp. 111-137). The proposed closure design was described as follows:

> The preferred closure concept is the hybrid approach described as follows: move all Primary and Secondary Pond ash into the Ash Fill 1 and 2 area; close Ash Fill 1 and 2 in place with an engineered cover system; remove Primary and Secondary Pond embankments and re-use the soil for cover system construction and pond area restoration; grade the ash pond areas to promote drainage and stabilization; and remediate groundwater (either passively or actively) and implement long-term groundwater monitoring.

Id. at pp. 118-119. This closure concept had been prefigured in the Company's operating plan for the waste units at Dan River as set forth in the 2008 Ten-Year Plan. In the Company's internal planning documents, this "hybrid approach" was sometimes referred to as a "brownfield" strategy, both terms referring to the construction of a new landfill disposal facility over top of or within the perimeter of an existing area of ash fill, capping the existing fill area in place and using the newly constructed landfill for future waste disposal or for relocation of existing waste from other storage areas. It is contrasted with a "greenfield approach," which referred to the construction of a new landfill on land not previously used to dispose of wastes. The January 2014 AMEC Plan concept design plan was consistent with the manner in which the Company had been operating and managing the impoundments since at least the time of the 2003 Ten-Year Plan.

By April 28, 2014, less than two months after the February, 2014 release into the Dan River, focus had shifted from the preferred concept in the January 2014 AMEC Plan. On that date AMEC submitted to the Company a second report evaluating various possible locations for an *off-site* "greenfield" landfill for disposal of the waste ash from the Dan River Plant. See Kerin Public Staff Direct Ex. 7 (Ex. Vol. 16, Part 1, pp. 138-75). By November 13, 2014, the Company had submitted to the North Carolina Department of Environmental Quality (DEQ)[28] what became, in concept, the closure plan for which the Company now seeks cost recovery in this case. Id. at 176-99. That plan, in pertinent summary, provides for removal of the ash in fill area 1, for transportation and offsite disposal of that ash followed by construction of an on-site lined landfill within the footprint of ash fill area 1. The ash waste in the two impoundments, after first being dewatered, would then be excavated and permanently disposed of in the newly constructed onsite landfill. This plan differed from the January 2014 AMEC Plan in one critical respect – the January 2014 AMEC Plan did not contemplate excavation and offsite disposal of the ash from ash fill area 1 prior to construction of a new landfill in that location.

At the hearing in this case, Company witness Kerin and Public Staff witness Moore vigorously debated the possibility that the Company could have constructed a new lined landfill on another portion of the plant site (a "greenfield" site), and thereby avoided the costs incurred to excavate, transport, and dispose of offsite the ash in fill area 1. I do not

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[28] Formerly known as the North Carolina Department of Environment and Natural Resources (DENR). DENR's name changed to DEQ effective September 18, 2015.

find it necessary to resolve that disagreement. Instead, I conclude that but for certain provisions contained in CAMA that were, I believe, directly connected and causally related to the Dan River ash spill in February, 2014, the Company would have been able to implement the January 2014 AMEC Plan, thereby avoiding the excavation, transport, and offsite disposal of the ash in fill area 1. I arrive at this conclusion based on the considerations set forth hereafter.

The bill that eventually was enacted as CAMA was originally filed on May 14, 2014, as S. 729, bearing the short title "Governor's Coal Ash Action Plan."[29] Section 10 of the bill singled out two of the Company's coal-fired generating plants, Dan River and Riverbend, and required prompt submission of closure plans for the surface impoundments at those plants and for permanent disposal of the ash in a lined structural fill, a lined landfill, or an alternative approved by DEQ. Dan River and Riverbend were the only two plants in the Company's fleet called out by name in the proposed legislation. The first edition of the filed bill contained recitals specifically referring to the Dan River Plant ash release and the fact that wastes from the release had settled into river bottom sediments, requiring extensive remediation.

The bill took substantially its final form in the Second Edition, which was adopted by the Senate Agriculture, Environment and Natural Resources Committee on June 17, 2014. All recitals in the original bill were dropped; however, the specific provisions targeting the Company's Dan River and Riverbend plants were retained in modified form. In all material respects for purposes of the present discussion, the bill remained unchanged thereafter until its enactment with an effective date of September 20, 2014. N.C.S.L. 2014-122.

CAMA contains a comprehensive scheme for regulation and eventual closure of all waste ash surface impoundments grounded on a risk-based priority classification – low, intermediate, and high – with the requirements for operation and closure, and the associated deadlines, increasingly stringent as the risk classification level increases. The determination of risk classification is to be made by DEQ on a site-by-site basis, based on extensive analysis and public input, except in four cases. In those four specific cases, the General Assembly pre-empted the general statutory scheme and declared that those sites were to be classified as high-priority sited and imposed a final closure date for the coal combustion residuals impoundments at those plants of August 1, 2019.[30] Those four sites, out of the entire fleet of the two Duke Energy affiliates operating in North Carolina, were Dan River, Riverbend, Asheville, and Sutton. All other sites were declared intermediate-risk for interim purposes with final risk classification to be established by DEQ later. The record in this case establishes that all of the Company's remaining waste surface impoundments were ultimately classified by DEQ as low-risk under CAMA. Tr. Vol. 16, pp. 38-42.

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[29] N.C. Gen. Assembly, S. 729. Reg. Sess. 2013-2014 (2014). The complete legislative history of S. 729 is available at https://www2.ncleg.net/BillLookup/2013/S729.

[30] N.C.S.L. 2014-122, § 3.(b).

The most significant features of the final low-risk classification of the waste impoundments at the Company's other plants are an extended target date for final closure in 2029 and the potential opportunity to use a cap-in-place closure strategy for the impoundments, that being the same closure strategy for which the Company had been planning and preparing since the mid-2000s. In other words, as CAMA is now being implemented, the Company's pre-CAMA preferred closure strategies are still potentially available for all of its plants, except Dan River and Riverbend.[31]

Based on the entire record, I conclude that the General Assembly's pre-emption of the general regulatory regime and its peremptory directive concerning closure of the impoundments at the Dan River Steam Station was a direct consequence of the Company's February, 2014 ash release into the Dan River. The General Assembly's action in this regard cannot be based on any other factors evidenced in this record that differentiate the Dan River impoundments from those at the Company's other coal-fired generating plants.[32] The extensive evidence presented by the Public Staff and other intervenors concerning seeps and groundwater exceedances at all of the Company's plants does not show any evidence of environmental compliance issues, groundwater exceedances, seeps, or other environmental contamination associated with the two Dan River impoundments that are materially greater than or different from those at any of the Company's other plants. <u>See, e.g.</u>, Ex. Vol. 26, p. 61; Ex. Vol. 16, Part 2, pp. 35-80; Wells Public Staff Cross Ex. 2, p. 4 (complete copy filed on April 5, 2018, pursuant to the Commission request's on the record during the evidentiary hearing); Kerin Sierra Club Cross Ex. 2; AGO Late-Filed Ex. 1, Tab K.

Several intervenors and the Company have wrestled over whether or not the entirety of CAMA can be attributed to the Dan River ash release. I do not take a side in that debate but instead reach a more limited conclusion here – that based on the internal structure and history of the legislation that became S.L. 2014-122, certain of its specific provisions *can* be directly linked to the February, 2014 ash release at Dan River. It is the consequences following from those specific provisions that occupy me here.

The legislative dictate that Dan River Plant impoundments be treated as "high-risk" had substantial and costly consequences for their method of closure. The Company's pre-spill closure design concept, which was consistent also with the operating history of

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[31] A high level summary description of the Company's pre-CAMA closure strategy for its ash basins is provided in Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839.) More detailed discussion of the Company's pre-CAMA closure strategies are contained in several of the documents referred to in Section I.C. hereafter.

[32] From the record presented it is not possible to draw a firm conclusion as to the rationale for the "high risk" designation of the Riverbend plant. Certainly, that designation cannot be attributed to the ash release at the Dan River plant in February, 2014, and the Company's mismanagement of the impoundments at Dan River. At the time CAMA was enacted the Riverbend plant was, however, subject to two pending suits alleging environmental contamination at the plant associated with waste ash impoundments, one in Mecklenburg County Superior Court brought by DEQ and the Southern Environmental Law Center and one pending in the United States District Court for the Western District of North Carolina brought by the Catawba Riverkeeper. See Junis Exs. 17 and 18 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 25-34.)

the impoundments, had been to consolidate the ash contents from the two impoundments in the unlined ash fill areas and then to cap the combined ash from the fill areas and the impoundments with a synthetic seal and a vegetative layer. This was not only the least cost closure method; it also could be implemented on a reasonably short schedule once the surface impoundments had been dewatered. (For estimates of cost and time to closure, see AGO Late-Filed Ex. 1, pp. 135-165, Tab J: Plant Demolition and Retirement Presentation for the Executive Governance Committee, dated October 14, 2013. Dan River ash basin closure costs commencing 2013 and concluding 2017 estimated to total $23,993,000.) Of course, we know now that the Company delayed commencement of ash basin closure from the proposed 2013 start date. We also know that the Company's total cost estimate for closure of the Dan River impoundments, not including inflation costs, are now estimated to be in excess of $222,994,117. See Revised Kerin Ex. 11 (March 22, 2018).

CAMA's high-risk classification of the Dan River Plant impoundments foreclosed the Company's earlier preferred closure plan because of two of the law's provisions. Section 3.(a) of CAMA would have permitted the Company to construct a new coal combustion residuals landfill on top of either of the two ash fill areas and then to remove the ash wastes from the surface impoundments for disposal in the newly constructed landfill. Such a new landfill would have required a liner system over the existing ash and one beneath the ash excavated from the impoundments and placed in the new landfill. The closure options permitted under Section 3.(a) of CAMA, however, do not include excavation of the ash from the two impoundments, and then consolidation of the fill ash and the excavated impoundment waste ash *in situ* with a final cover or cap over the combined waste but without a liner under the ash.

Although as just noted Section 3.(a) permitted the Company to construct a new, lined landfill on top of the ash fill areas, Section 5.(a) of CAMA placed a moratorium on the Company's ability to construct any new landfill on the site of ash fill area 1, meaning that the Company could not immediately begin the process of constructing a landfill in or over ash fill area 1 until that moratorium expired.[33] As witness Kerin testified, the moratorium caused considerable anxiety about the Company's ability to meet CAMA's August 1, 2019 deadline for final closure of the surface impoundments at Dan River Plant.

The moratorium only applied to new "coal combustion residuals landfills," which were landfills constructed on top of areas presently or previously used for coal ash waste storage or disposal, meaning that the Company was free during the period of the moratorium to explore options for construction of a new landfill on a "greenfield" site. During the period between February 2, 2014, and November, 2014, when the Company submitted its proposed action plan to DEQ, the Company did investigate and consider its "greenfield" options. I concur in the majority's findings that neither the Hopkins tract, which was investigated by the Company, nor an onsite area west of the existing plant, recommended by Public Staff witness Moore, were reasonably available alternatives and

[33] The moratorium was to expire and did expire on August 1, 2015, pursuant to Section 5.(c) of CAMA. N.C.S.L. 2014-122, § 5.(c).

that the Company acted prudently in declining to pursue these "greenfield" options. This does not, however, explain why the Company commenced immediate excavation and offsite disposal of the wastes in ash fill area 1, an area that was not itself subject to CAMA's requirements nor to the (at that time pending) CCR Rule. The Company cannot defend this decision on the grounds that excavation and offsite disposal of the ash from fill area 1 allowed it to move forward more rapidly with construction of a new onsite landfill. Excavation of ash fill area 1 did *not* exempt an attempt to construct a new landfill in that area from the moratorium imposed by Section 5.(a) of CAMA. This is so because "coal combustion residuals landfills," whose construction was subject to the moratorium, were defined in G.S. 130A-290(a)(2c), as that statute was amended by CAMA, to mean:

> …a facility for the disposal of combustion products, where the landfill is located at the same facility with the coal-fired generating unit or units producing the combustion products, and where the landfill is located wholly or partly on top of a facility that is, *or was,* being used for the disposal of such combustion products, including, but not limited to, landfills, wet and dry ash ponds, and structural fill facilities.

(emphasis added.) Excavation of ash fill area 1, an unregulated facility, did not accelerate the Company's ability to construct a new landfill on that area and did not, therefore, enhance its ability to meet CAMA's mandated final closure deadline of August 1, 2019.

Nor was excavation and offsite disposal of the ash in fill area 1 necessary in order to enable the construction of a new landfill in that area. Again, Section 3.(a) of CAMA permitted the excavation and disposal of ash wastes from the two surface impoundments in a new "coal combustion residuals landfill," which as noted in the definition quoted above, is a facility located "…wholly or partly on top of a facility that is, or was, being used for disposal …" of waste coal ash.

From a close review of witness Kerin's testimony, I conclude that the Company's decision to commence immediate excavation and offsite disposal of the wastes in ash fill area 1 was not based on any consideration of least-cost options, was not dictated by CAMA, was not required in order to enhance the Company's ability to comply with CAMA, and did not in fact accelerate the construction of a landfill within the footprint of ash fill area 1. Instead, I conclude from the testimony that the Company's actions were in fact driven by the pressure it felt in the aftermath of the Dan River release to, put in the vernacular, "do something, do anything, just do something." Tr. Vol. 25, p. 27-28; Tr. Vol. 7, pp. 13-15. My conclusion is further confirmed by the fact that the internal processes for bidding and contracting for excavation and offsite disposal of the ash from the Dan River ash fill commenced in July, 2014, and bids were in hand by October 9, 2014. Kerin Direct Public Staff Direct Ex. 5 (Ex. Vol. 16, pp. 111-113). This time period coincides with the movement of S. 729 through the legislative process, and it *precedes* the Company's submission of its excavation plan for Dan River to DEQ on November 13, 2014. Kerin Direct Public Staff Cross Ex. 9 (Ex. Vol. 16, pp. 181-203).

In consideration of the foregoing, I would deny the Company's request to recover **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** spent for excavation, transport, and offsite disposal of the wastes from ash fill area 1. These costs are amounts that would not have been expended under the Company's preferred closure plan embodied in the January 2014 AMEC Plan, and are therefore identifiable and quantifiable. Based on my conclusion that the Company's imprudent management of the surface impoundments at Dan River, resulting in the ash release into the Dan River in February, 2014, is the direct cause of the Company's inability to implement the preferred closure plan, I likewise would disallow all costs incurred by the Company for closure activities at the Dan River Plant in excess of amounts otherwise required to implement the January 2014 AMEC Plan. Unfortunately, however, the record does not include any cost estimates for the January 2014 AMEC Plan, and it is most likely that the occurrence of the ash spill on February 2, 2014, pre-empted any further development of such cost estimates. In the event the matter is brought before the Commission in the future and in a proper procedural context, the question whether these excess costs can be quantified will warrant further inquiry.[34]

C. <u>The Company's Handling of Cost Recovery for Anticipated Waste Ash Disposal Costs</u>

I do not disagree with the majority's decision to permit the Company to account for its ongoing and future ash basin closure costs in accord with SFAS 143, at least as it pertains to the closure of ash storage and disposal facilities that are subject to one or more of the federal CCR Rule, CAMA, or applicable final judicial and/or administrative orders.[35] My concern in the present discussion centers on the manner in which the

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[34] The Company's Riverbend plant was, like the Dan River Plant, also pre-emptively designated by the General Assembly in CAMA as a "high-risk" site. The Company's preferred pre-CAMA closure strategy for Riverbend had been to cap the existing impoundments in place, but this option was foreclosed by CAMA. Some of the Company's internal documents, however, suggest an awareness by the Company that the cap-in-place concept might not have been ultimately viable at Riverbend because the plant was located in an area designated as a "critical watershed" for public drinking water supplies. <u>See., e.g.</u>, Kerin Direct AGO Cross Ex. 2, p. 253. For this reason, among others, I do not believe the record would support any finding that the Company's imprudent actions or omissions are responsible for the closure strategy ultimately adopted and implemented for the Riverbend plant.

[35] The central focus of all parties in this case has been on the surface impoundments used to store coal ash wastes. These impoundments are subject to both the CCR Rule and CAMA, and have been the subject of several judicial and administrative decrees. Over time, the Company has operated other ash storage and disposal facilities at some of its plants that are not regulated under CAMA, the CCR Rule, or any other regulatory regime. The record does not permit a determination as to whether or not the costs of closure of all of these dry storage areas qualify for accounting treatment under SFAS 143 or whether, instead, they should continue to be recorded and reported under the principles set out in SFAS 19. In its discussion of ARO accounting the majority order refers to and discusses the December 21, 2015 letter from Brian Savoy (Savoy Letter), notifying the Commission that the Company would implement SFAS 143 accounting treatment for its waste ash basin closure costs. One point in the Savoy Letter bears upon a subsidiary issue but requires comment here. The letter states: "Coal Ash Basin costs that relate to activities outside the scope of the aforementioned legally required activities (e.g., Federal CCR rules and the NC CAMA legislation) are being expensed immediately as Operations and Maintenance (O&M) expense." In the course of the hearings on the Company's current application, the Company was asked whether the closure costs associated with non-CAMA and non-CCR Rule regulated sites, specifically the inactive ash basin and the borrow area at the Lee Plant, were included in the Company's reported ARO liabilities.

Company accounted for and treated for ratemaking purposes the anticipated costs for closure of the waste ash storage and disposal facilities before it established ARO accounting for those costs. This is a topic not addressed by the majority in its opinion, and I believe this omission is error.

Before the promulgation of SFAS 143, and afterward for all cases that do not fall within the jurisdictional scope of SFAS 143, costs expected to be incurred upon the retirement and decommissioning of a long-lived asset were typically estimated as part of the terminal net salvage value of the asset, which was a component of depreciation. For regulated entities these anticipated costs of removal were included in allowed depreciation expense and were collected in rates. Costs of removal include such items as dismantlement and demolition of structures, sale of salvaged equipment and materials, site restoration, and any necessary environmental remediation costs. When costs of removal were expected to exceed the salvage value of reusable and useful facilities, equipment and materials, terminal net salvage value would be a negative number, and this would serve to increase the annual depreciation expense associated with the long-lived asset. <u>See, e.g.</u>, the discussion in Doss Ex. 3, p. IV-2 (Ex. Vol. 12, p. 787). Typically, though not in all cases, accumulated depreciation was recorded for financial statement reporting purposes as a "contra asset," that is, as a deduction from the carrying value of the associated asset on the balance sheet. Usually, though again not always, costs of removal were not adjusted for future inflation or discounted to present value, although they would be subject to adjustment according to periodic updates to depreciation studies and resulting changes to depreciation rates.[36]

The Company's position in this case is that it first became subject to the financial statement reporting requirements of SFAS 143 upon the enactment of CAMA and the adoption of the CCR Rule. While I believe an argument can be made from the evidence presented in this case that earlier application of SFAS 143 might have been required in the case of at least some of the Company's waste ash units, for purposes of the present discussion, I have accepted the Company's position concerning the triggering events for conversion from traditional depreciation accounting for costs of removal to accounting under SFAS 143.[37]

Because it is the Company's position that the September, 2014 consent agreement triggers ARO accounting for these two waste units, the Company reported in its April 6, 2018 filing showing that the costs associated with these two facilities were included in reported ARO liabilities. However, that letter appeared to speak more generally also, saying that estimates and actual expenditures "… are not tracked on a basin-by-basin basis, but on a site-by-site basis." This statement needs to be reconciled with the portion of the Savoy Letter quoted above. I believe the Commission should direct the Company to identify all such unregulated waste units for which closure tasks are being performed and for which costs are being incurred and confirm that no portion of those costs are included in the ARO liabilities reported in Kerin Direct Ex. 11 in this case or in the allowed amounts that are being deferred and amortized by the Majority Order in this case.

[36] This summary is largely drawn from the more detailed explanation of the concepts contained in SFAS 143 and SFAS 19.

[37] In brief summary, the argument would be that final closure of ash storage and disposal facilities upon retirement was a known requirement under the regulatory regime established pursuant to the Clean

It is likewise the Company's position in this case that before its adoption of ARO accounting for the waste impoundment closure costs, it had not included any estimated costs for such closures in its estimation of terminal net salvage values for the generating plants of the impoundments served, and did not, therefore, include any such amounts in its depreciation rates requested and approved under G.S. 62-133(b)(3). Thus, the Company did not collect any such amounts from ratepayers in prior rates. Company witnesses Spanos and Kopp, who prepared and explained the depreciation study offered by the Company in this case, testified that the depreciation study and the requested rates based on that study included no costs of removal for the waste ash impoundments and that, moreover, the depreciation studies and requested rates in the Company's prior rate cases in 2007, Docket No. E-7, Sub 828; in 2009, Docket No. E-7, Sub 909; in 2011, Docket No. E-7, Sub 989; and in 2013, Docket No. E-7, Sub 1026, likewise had included no amounts for costs of removal of the ash impoundments. *They testified that this was so because they had not been asked to include any such elements of cost in their depreciation studies and had been given no information on the subject.* See Tr. Vol. 9, pp. 124-125.[38] Based on this evidence, I find it legitimate to ask whether it was reasonable and prudent for the Company to have omitted all costs of removal for the ash impoundments from its requested depreciation rates in any of its rate cases prior to this one and, if not, what consequences should follow from that omission.

Other evidence in the case, notably Fountain AGO Cross Ex. 6 (Ex. Vol. 10, pp. 609-694) establishes that the Company *did* estimate negative terminal net salvage values for its coal-fired generating plants, *did* include those negative values in the calculation of its requested depreciation rates, and *did* include those negative values in rates collected from customers. Apparently, however, those negative values addressed only plant decommissioning costs other than costs of closure of the waste ash impoundments at the coal-fired plants. Fountain AGO Cross Ex. 6 is a slide presentation titled, "Ash Basin Closure Update," dated January 13, 2014, only days before the ash release at the Dan River Plant, made to the Company's Senior Management Committee on the status of the Company's activities and plans, and those of its regulated affiliates, relative to management of coal ash wastes. Among the topics covered in the presentation

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Water Act, and that the costs of closure were reasonably subject to estimate, and in some cases were in fact estimated by the Company, well before the enactment of CAMA or the CCR Rule. In any event, I do not base my conclusion here on any finding that the Company should have requested approval of ARO accounting any sooner than it did.

[38] Under the transition provisions in SFAS 143, when ARO accounting treatment is established for an existing long-lived asset for which depreciation has been and is being taken, the accumulated depreciation is incorporated in a cumulative adjustment to the financial statement, essentially being taken as a credit or reduction of the amount of the recognized and recorded ARO liability. If, as is the testimony in this case, no costs of removal had been collected in depreciation expense, then no credit would have been booked to the ARO liability recorded when the Company adopted SFAS 143 treatment for its ash impoundment closure costs.

was the recovery of costs associated with closure of the ash basins at each of the Company's coal-fired generating plants.[39]

One presentation slide discloses that the Company had collected through depreciation expense costs of decommissioning for its coal-fired plants of some $224 million and that it was possible that some or all of this amount could be tapped to offset a portion of expected costs for closure of the ash basins.[40] At the time of the presentation, the Company's costs to close the ash impoundments, assuming, as in fact turned out to be the case, that the wastes would retain their non-hazardous classification, was estimated to be approximately $610 million. Again, though, the accumulated cost of removal amount for the coal-fired plants, according to the Company's testimony presented in this case, did not include any amounts for the ash impoundments themselves, so any use of the accumulated amount would have potentially left the Company facing insufficient cost recovery for its other plant decommissioning costs.[41]

A final bit of confirmation that the Company's depreciation expense included in its rates did not include any amounts for costs of closure of its waste ash impoundments comes from the application in Docket No. E-7, Sub 1110, which is the Company's application for a regulatory accounting order allowing it to use ARO accounting for expected ash basin closure costs. In its filing, a joint filing with its affiliate DEP,[42] the Company commented that DEP had been collecting as part of costs of removal a specifically earmarked sum for coal ash impoundment closure costs since its last general rate case in 2013. <u>See, e.g.</u>, Docket No. E-2, Sub 1023. Nothing similar was disclosed or reported with respect to the Company's own posture on the subject. <u>See also</u>, AGO Late-Filed Ex. 1, Tab L, p. 25, stating: "DEP in the Carolinas, very recently started including recovery for specific ash pond closure costs in their COR rates. DEC still does not have specific related ash pond closure costs in the COR rates."

The Company very clearly knew that costs of removal upon plant decommissioning were a proper component of terminal net salvage values and thus a proper and

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[39] I note that this presentation, and most of the other documents I will review, were all dated prior to the enactment of CAMA, prior to the adoption of the CCR Rule, and prior to the Company's plea agreement in its federal criminal case.

[40] This amount is referred to as a "reserve," but it did not represent a segregated fund in the same sense as, say, the nuclear decommissioning trust fund. It instead represented amounts included in rates pursuant to G.S. 62-133(b)(3), but, as noted in the presentation, the Company would nonetheless have to identify a source of cash for the expenditures to which this "reserve" had been accumulated. In addition to the amount separately identified as accumulated costs of removal for the steam plants, the document also disclosed the total accumulated costs of removal for all other asset groups other than nuclear plant, including non-coal generating units, transmission system assets, and distribution system assets.

[41] The same information contained in Fountain AGO Cross Ex. 6 is also provided in a post-hearing exhibit filed by the Attorney General in response to questioning by Commissioners concerning the possible existence of other documents addressing the subject matter of Fountain AGO Cross Ex. 6 <u>See</u> AGO Late-Filed Ex. 1, Tab L.

[42] The Company's filing is assigned Docket No. E-7, Sub 1100. The companion filing by DEP was assigned Docket No. E-2, Sub 1103.

recoverable element of depreciation expense. Should it have included costs of closure for the waste impoundments in its broader estimate of decommissioning costs and, if so, when should it have done so? Answering this question requires, I believe, examination of two things: the development of industry standards and best practices concerning the decommissioning of coal-fired generating plants and their associated waste ash storage and disposal units, and the Company's own internal policies and planning for the retirement of its fleet of coal-fired plants, including the associated ash impoundments, in the time period before the enactment of CAMA in 2014 and adoption of the final CCR Rule in 2015.

The earliest evidence in the record bearing upon these questions is contained in the Electric Power Research Institute's (EPRI's) Coal Ash Disposal Manual, Second Edition, published in October, 1981. Kerin Sierra Club Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 281-356; complete report filed by Sierra Club on March 15, 2018). The manual is a comprehensive treatment of the then state-of-the-art theory relative to a number of topics, including procedures and practices for closure of waste ash storage and disposal facilities. In its scope section, the manual explains:

> The purpose of Section 8, Site Reclamation, is to present information on site reclamation procedures for ash disposal areas. Because of increased environmental awareness, increased concern for site aesthetics and resulting public opinion, and more stringent environmental regulations, efforts to reclaim and revegetate disposal sites have recently accelerated; however, there is considerable confusion regarding which methods are appropriate …. To assist utility personnel in dealing with site retirement procedures in their area, this section gives specific guidance to effective and economical site retirement and revegetation procedures, as well as sources of additional information and assistance.

Id. at 287.

Section 8 of the manual contains an extensive technical and environmental analysis of methods of retirement and closure for ash storage and disposal facilities, including landfills and surface impoundments. The preliminary scope statement for Section 8 reads:

> The advent of recent federal and state laws involving clean water and waste disposal standards has created a need to closely manage the progression and final closure of ash disposal sites.

Complete EPRI Report filed by Sierra Club, p. 8-1 (March 25, 2018).

This EPRI Report is of particular interest because two of the field sites studied and reviewed in the manual were the Company's Allen and Marshall Steam Stations. In Section 6, the manual describes activities being undertaken by the Company at the inactive ash basin at its Allen Plant to experiment with different types of soil cover and different types of revegetation following decommissioning of the basin. It was clear that as early as 1981, closure and reclamation of retired ash storage and disposal facilities was a topic for which utilities were planning and were expected to be planning, and that the Company itself was already experimenting with closure techniques at its Allen Plant.

In August, 1982, EPRI published a second report titled Manual for Upgrading Existing Disposal Facilities, which addressed practices, standards, and options for addressing deficiencies identified in the course of operating existing ash storage and disposal facilities. Kerin Sierra Club Cross Ex. 2 (Ex. Vol. 16, Part 1, pp. 224-262). The manual notes that its purpose was "… to provide the industry with detailed information about design features, equipment selection, and specific procedures for evaluating current disposal system suitability and selecting optimal retrofit systems for existing disposal facilities." Id. at 226. The EPRI Manual was based on survey research and field site research. Summarizing the deficiencies most often noted in field inspections, the report identified four of particular note, one of which was "closure/post closure plans were inadequate or nonexistent." The manual included not only procedures and recommendations for upgrading facilities and correcting deficiencies but also a methodology for calculating the costs of various upgrades.[43]

By not later than the 2000s, the matter of retirement and decommissioning of coal-fired generating plants constructed in an earlier era had become a topic of greater focus. In November, 2004, EPRI published another manual, this one titled Decommissioning Handbook for Coal-Fired Power Plants. Ex. Vol. 10, pp. 695-782. The manual alerted its users that:

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[43] This manual is of particular interest in light of witness Kerin's testimony that in the absence of a regulatory directive to do so, it would not have been reasonable for the Company to modify existing ash impoundments that were still receiving wastes and operating under NPDES permits. Tr. Vol. 14, p. 110. I find that the EPRI Manual confirms that the "minimum required by law" standard of operation advanced in some of the Company's testimony through its witnesses Kerin, Wright and Wells is simply wrong. In its preliminary pages, the EPRI Manual notes:

> Potential deficiencies in utility waste disposal practices may be defined by two sets of standards:
>
> -The disposal practice does not comply with specific federal and/or state regulatory requirements.
>
> -The site has the potential to contaminate the environment.
>
> This seemingly redundant statement is important to any assessment of disposal site deficiencies. Identification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to the regulations.

Ex. Vol. 16, Part 1, pp. 240-241.

The 1982 EPRI manual is not the only document in the record that communicates this same point. A minimalist view of the requirements of "prudence" simply does not comport with actual industry practices and standards or, as we shall see, with the Company's own view, at least as set out in documents authored prior to this case.

> [t]here are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contaminations as well as the best methods of removing and disposing of the substances.

Id. at 704. Discussing the various tasks and costs that could be expected as part of the retirement of a plant, the manual later observed that "[c]losure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project," (Id. At 722), and followed this with the explanation that

> [c]losure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. … The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Id. at 724. The manual provided three case studies of plant decommissioning, along with a discussion of the estimated or actual costs incurred. One of the examples was Georgia Power Company's Arkwright Plant, which had ceased operations in 2002, and where final site cleanup was expected to be completed in 2006. The study reported that the costs for closure of waste ash surface impoundments at the Arkwright plant were estimated to be $10,700,000, or some 56.3% of total decommissioning costs net of salvage recovery. Id. at 753. For the Tennessee Valley Authority's Watts Barr plant, finally retired in 2000, the costs for closure and remediation of both dry ash units and surface impoundments were estimated to be $9 million, out of a total cost range estimated to be between $17 million to $25 million in 2000 dollars. Id. at. 754. From the Decommissioning Manual it was clear that the costs of closure of waste ash disposal facilities would not be a trivial or *de minimis* item.

The Company was not unaware or unmindful of the industry practices and learnings evidenced in reports and studies such as these three EPRI manuals and had incorporated them into its own internal policies.[44] Based on the entire record, I conclude,

[44] For brevity, I have selected these three EPRI documents as representative of industry knowledge and practices. The record contains numerous other documents that are fully consistent with and support the conclusions I draw here, including Junis Public Staff Exhibit 4 (Environmental Control Implications of Generating Electric Power from Coal, Argonne National Laboratory, December, 1976); Kerin Sierra Club Cross Ex. 3 (Los Alamos Scientific Laboratory, The Disposal and Reclamation of Southwestern Coal and Uranium Wastes, May, 1979); Junis Public Staff Ex. 9 (Proceedings of the American Society of Civil Engineers, Water Quality Issues at Fossil Fuel Plants, October, 1985, including a case study of releases of selenium from the Company's Belews Creek Steam Station); Kerin Sierra Club Cross Ex. 5 (EPA Report to Congress, Wastes from the Combustion of Coal by Electric Utility Power Plants, 1988); Wells Public Staff Cross Ex. 6 (Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June, 1985, including in particular a field evaluation and analysis of coal waste handling practices and environmental conditions at the Company's Allen Steam Station; and Ex. Vol. 12, pp. 220-290; and Wright, Public Staff Cross Ex. 5 (EPA Office of Solid Waste, Coal Combustion Waste Damage

on a conservative basis, that by not later than the time of its 2009 general rate case, and most likely sooner, the Company had formed an understanding that: (1) permanent closure of its waste ash storage and disposal facilities would be required when the associated coal-fired generating units were retired, if not sooner; (2) closure of these waste units would constitute a substantial portion of the total costs of decommissioning the plants; (3) planning and investigation of options and development of timetables should begin well in advance of the time of actual plant retirement; and (4) provisions for cost recovery of such closure costs should be developed. These points are extensively developed and documented in a series of internal Company documents, including the following:

- Ten-Year Coal Combustion Products Plan, 2003 (Kerin AGO Direct Cross Ex. 1)
- Ten-Year Coal Combustion Products Plan, 2008 (Kerin Direct Public Staff Cross Ex. 2)
- Duke Energy Environmental Management Program for Coal Combustion Products, dated May 29, 2007, (Kerin AGO Direct Cross Ex. 3)
- Environmental Management Program for Coal Combustion By-Products, dated June 27, 2007 (Kerin AGO Direct Cross Ex. 5)
- 2012 Plant Retirement Comprehensive Program Plan (Doss AGO Cross Ex. 1)
- Guidance on Developing Closure Plans for Ash Basins, September 27, 2012 (AGO Late-Filed Ex. 1, Tab A)
- Ash Basin Closure Strategy, (AGO Late-Filed Ex. 1, Tab E)(undated, but from internal evidence in the document likely dated in 2013)
- Demolition and Plant Retirement Presentation, dated February 16, 2013 (AGO Late-filed Exhibit 1, Tab F)
- Environmental Talking Points for Presentation to Board of Directors, August 27, 2013 (AGO Late-Filed Ex. 1, Tab I)
- Plant Demolition and Retirement Presentation for the Executive Governance Committee, October 14, 2013 (AGO Late-Filed Ex. 1, Tab J)
- Ash Basin Closure Strategy Presentation to the Senior Management Committee, November 25, 2013 (AGO Late-Filed Ex. 1, Tab L)[45]

Case Assessments, July, 2007). These documents all demonstrate that industry knowledge with respect to the environmental risks and implications of coal waste handling practices was more advanced at an earlier date than contended for by some of the Company's witnesses and that recommended best practices were, since at least the early 1980s, more sensitive to environmental concerns than represented by a bare minimum standard of regulatory compliance.

[45] Consideration of these critical internal policy documents is, by and large, missing from the discussion in the majority order. All of these documents pre-date the enactment of CAMA or the CCR rule. Even under the law as it existed during that time, the Company knew that regulatory closure would be required when the ash basins were retired. Representative is the following statement from an undated document likely authored in 2012 or 2013:

> Currently, federal regulatory programs do not specifically address the decommissioning and closure of ash basins; however, state regulations provide some options for closure framework. The

The intensified focus on closure of coal ash waste facilities in the 2000s was driven in large part by the aging of the Company's existing fleet of generation units and by the economics that increasingly favored conversion from coal to natural gas as a fuel. From this internal evidence it is clear that the Company was on notice throughout the decade of the 2000s and into the present decade, that the costs of removal of its waste ash storage and disposal facilities would affect, most likely very significantly, terminal net salvage values of its plants and thereby the amount of allowance it should seek to recover from ratepayers as depreciation expense. However, according to the testimony in this case, at no time during that period, including in its general rate cases in 2009, 2011, and 2013, did the Company include any provision for such costs of removal in its depreciation studies presented to the Commission. At least some portion of the costs the Company now seeks to recover in rates prospectively thus represents amounts the Company could have, and in my judgment prudently should have, recovered through depreciation expense in its existing and previously approved rates.

My view on this point is I believe in line with the Commission's decision in Order Granting Partial Rate Increase, Docket No. W-218, Sub 319 (November 3, 2011) (Aqua Order). In that proceeding, Aqua and the Public Staff disagreed as to the propriety of including in depreciation expense, and thus in rates, amounts for terminal net salvage value that would also incorporate costs of removal. The Company's witnesses pointed out that including these amounts in current depreciation expense would properly assign a portion of expected future expenses to those customers who were currently receiving the benefit of the utility plant while it was still in service. The Public Staff contended that such a practice would improperly require present customers to pay for future costs that might or might not actually be incurred, or might be different in amount at the time actually incurred. As to this difference of opinion, the Commission noted the applicant's testimony in the following summary:

> Witness Spanos[46] advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice[47] of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts.

> company is working closely with NCDENR to define a closure process that provides a framework for certainty in the absence of specific federal regulatory requirements.

AGO Late-Filed Ex. 1, Tab E (Filed on April 18, 2018.)

[46] This is the same witness Spanos who testified for the Company in the present case.

[47] Elsewhere in the Aqua Order, it is made clear that "new practice" means "new for this applicant," not new for the accounting profession. Prior to Aqua's 2011 rate case, Aqua North Carolina had not been computing net salvage values as part of depreciation expense.

Aqua Order at 70. Aqua Witness Spanos further explained that the entire cost of the asset, including costs of removal, should be recovered over the useful life of the asset and not recovered from customers after the asset's useful life had ended. Id.

In its order the Commission disagreed with the Public Staff's position and instead sided with the Company and its depreciation expert, witness Spanos, finding that:

> …utilizing the net salvage value percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. *This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts.*

Id. at 72 (emphasis added).

In the present case, the Company's failure to seek recovery of waste ash storage and disposal costs as part of current depreciation expense in prior rates means that some portion of the properly allocable full cost of providing service to an earlier generation of customers will now be shifted to, and recovered from, future ratepayers. This is not in keeping with the sound policy and principles endorsed in the Aqua Order, nor do I believe it is consistent with the principles stated and endorsed by the Supreme Court in State ex rel. Utilities Commission v. Edmisten (Edmisten III), 291 N.C. 451, 232 S.E.2d 184 (1977). The Company is now seeking to recover from present and future ratepayers a cost that is attributable to service provided to ratepayers in prior periods. That cost is depreciation expense, more precisely that portion of depreciation expense representing the costs of removal upon final facility retirement that should be allocated among ratepayers over the entire useful life of the asset and not fall entirely upon those ratepayers at the time retirement occurs and funds are expended for decommissioning.

Some intervenors in this case have suggested that for any waste ash storage or disposal facilities associated with a generating plant, these costs of removal should have been collected through depreciation since the time the waste ash facility was first placed in service. On the present record, however, it is not possible to reconstruct this scenario today, and I have concluded that it is more reasonable to use as a beginning point the time the Company first knew or reasonably should have known, based on information available to it at the time, that it would incur substantial costs to close the waste facilities at the time of plant retirement and decommissioning. Based on the evidence recited earlier, this point in time was manifestly earlier than the date of enactment of CAMA or the adoption of the CCR Rule. I also conclude that it was at a point in time that predates the Company's general rate cases in 2009, 2011, and 2013, in none of which did it seek any provision for cost recovery of then-anticipated cost of removal of the waste ash storage and disposal facilities.[48]

The difficulty, of course, lies in determining how much cost has been improperly and imprudently shifted from past customers for service previously received, to present and future customers for service yet to be provided them. One device would be to look to the actions of the Company's affiliate, DEP, which requested and received approval in its 2013 general rate case to collect $10 million per year from customers for estimated costs of removal of its waste ash facilities. I do not find this option acceptable, however, since it ignores pertinent differences in the two companies' history of management of coal ash wastes and, more importantly, in the physical, environmental, and economic circumstances of their fleet of coal-fired plants and their associated waste ash facilities.

From the available evidence in the record I find that the cost estimates contained in two exhibits, Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839) titled "Plant Retirement Comprehensive Program Plan," and Atty. Gen. Late-Filed Exhibit 1, Tab J, titled "Plant Demolition and Retirement Presentation for the Executive Governance Committee," dated October 14, 2013, are the most appropriate to use for present purposes. The Plant Retirement Comprehensive Plan, dated October 31, 2012, sets forth the Company's then best estimates of plant decommissioning costs and, separately from general costs, costs for closure of waste ash storage and disposal facilities at the retired plants.[49] For the four coal-fired plants already retired or for which a near-term retirement date had been established - Buck, Dan River, Riverbend, and W.S. Lee – the estimated costs for closures of ash storage and disposal facilities totaled $115,538, 470. Interestingly, the estimate for other decommissioning tasks at these four retired plants totaled $32,323,875, confirming the statement in the 2004 EPRI plant decommissioning handbook that the costs of closing waste storage and disposal facilities would likely be the largest portion of plant decommissioning expense. The budgeted figures for closure of the waste ash facilities at the Buck, Dan River and Riverbend plants contained in the October, 2013, Plant Demolition and Retirement Presentation is $111,361,000. This total is less than the aggregate total in the 2012 comprehensive plant retirement plan, but it does not include any estimated costs for the waste facilities at the W.S. Lee Steam Station. Comparing

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[48] There is nothing in this record to show that in setting the Company's prior rates the Commission was presented with any evidence concerning costs of removal for the waste ash impoundments apart from the general estimation of terminal net salvage values for the coal-fired generating plants contained in depreciation studies prepared by the Company's experts and relied upon by the Commission. For example, in Docket No. E-7 sub 1126, the Company's last general rate case before the instant proceeding, the depreciation study for each generating plant contained a negative allowance for terminal net salvage value for "Structures and Improvements," (Docket No. E-7, Sub 1126, Wiles Direct Ex. 3, p. 47), without further breakdown of the elements of cost entering into the calculation. Based on the evidence before it, the Commission had no ability to assess whether the Company had correctly or incorrectly identified and incorporated all the tasks that would be required upon plant retirement or whether it had identified and incorporated all the estimated costs of those necessary tasks. It was incumbent upon the Company to petition for and present evidence of the amounts needed to cover its known and expected expenses, including depreciation expense. E.g., New Jersey Power & Light Co. v. State Dep't. of Public Utilities, 15 N.J. 82, 92; 104 A.2d 1, 18 (1954)(cited with approval in Edmisten III).

[49] This plan is not a mere proposal; it carries all necessary approval signatures.

"apples to apples," the total estimate in the 2012 plan for the Buck, Dan River and Riverbend plants only was $93,272,969, meaning that the budget for closure activities at these three plants increased by $18,089,031 between 2012 and 2013. Both the 2012 and 2013 documents estimate expenditures over the same time period – 2013 through 2018. If the 2012 estimated closure budget for the W.S. Lee plant is added to the revised 2013 budget number for the Buck, Dan River and Riverbend plants, then the resulting total would be $133,626,501. As a point of comparison, this total is dramatically less than the $1,267,692,514, including in that total amounts for expected inflation, the Company now estimates it will spend over the next fifty years for closure of the waste ash units at these four plants. See Kerin Direct Ex. 11, p. 1.

Based on the available evidence, I find that the Company should have sought to collect in present and previously approved rates as costs of removal for the waste ash facilities at its four retired coal plants an amount not less than $133,626,501, and that its failure to do so was unreasonable and imprudent based on its knowledge at the time. Considering our obligation to be fair and reasonable both to ratepayers and to the Company and the requirement that we judge the Company based on information known to or reasonably available to it at the time of its conduct under examination, I conclude that the Company's present request in this rate case for recovery of amounts expended during 2015 through 2017 should be reduced by the amount of $133,626,501. Given the Company's long-standing and extensive knowledge of the types and magnitudes of costs it would have to incur, the certainty even before CAMA and the CCR Rule that it would be incurring them upon plant retirement, and its failure to seek to spread these costs equitably to all ratepayers who received benefit from the electricity service that caused such costs to be incurred, I believe this is a just and reasonable result. It avoids transferring to present and future ratepayers costs that should have been collected from ratepayers in prior periods.

Strictly applying the foregoing principles and analysis, it is unquestionably true that some amounts should also have been requested in depreciation rates prior to the present case for estimated costs of closure of waste ash facilities at the Company's operating plants, Allen, Belews Creek, Cliffside, and Marshall. However, in this record there is no evidence upon which a reasonable judgment could be made as to the additional amount attributable to these plants.[50] I note that the Company's cost recovery request for coal ash expenditures in 2015, 2016, and 2017 at these four plants largely consists of items that would be classified as inspection, maintenance, and repair activities at the existing waste impoundments, together with site assessment, planning and closure plan preparation activities. Actual costs for dewatering, consolidating, excavating, capping, and similar closure tasks remain for the future. There will be opportunity in the Company's

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[50] Some closure estimates are provided in AGO Late-Filed Ex. 1, Tab L, p. 34 based on three different closure scenarios. These estimates are in a document dated November 25, 2013, after the filing of the Company's most recent general rate case application preceding the present one. I am unable to extract from this evidence, however, any reasonable estimate of amounts that the Company should have attempted to collect as costs of removal in prior rate cases. I consider the evidence more reliable in the case of the four retired plants because their retirement had been planned and information concerning closure of the ash impoundments had been studied and assembled over a period of years prior to the 2012 and 2013 estimates upon which I rely.

next general rate case to consider further the issue discussed here as it may relate to the Company's remaining coal-fired plants.

II. Rate of Return on Unamortized Coal Ash Waste Costs and "Mismanagement Penalty"

In this part I address my disagreement with the majority's decision to permit the Company to earn an investment return, equal to the weighted average cost of capital, on the deferred unamortized balance of its expenditures on closure of coal ash impoundments during the years 2015 through 2017 and its decision to impose a penalty for mismanagement of the ash basins in the amount of $70 million. Though these appear to be separate decisions, they are necessarily linked. The Commission first proposes to allow the Company to earn a return that I believe is, as to some of the costs involved, contrary to law and as to other portions of the costs, an abandonment of sound policy and practice and, on the record taken as a whole, an improper exercise of discretion. Having made this allowance, the Commission then reduces the total amount of the permitted return by $70 million and terms that reduction a "penalty" for mismanagement. Because there is no penalty if there is no allowed return on the unamortized balance of the waste ash costs, I focus my dissent on the first of these two decisions.

By way of opening I refer to and adopt in this case my rationale for denying a return on the unamortized balance of ash impoundment closure costs contained in my dissent in the DEP Rate Case Order. From the record assembled in this case, I have identified additional grounds to support the conclusion reached in my dissent in the prior case. On some points these additional grounds are based on matters and facts that may also have been pertinent to the decision in Docket No. E-2 sub 1142 but as to which the record was either silent or insufficiently complete to enable a judgment to be formed in that case.

A. <u>SFAS 143, Ratemaking, and Property "Used and Useful"</u>

The first issue I address is the irrelevance of SFAS 143 (now codified as ASC 410) to the issue at hand. The majority order has, I believe, conflated concepts of financial statement presentation with the classification of costs for ratemaking purposes. To avoid repetition I will not reprise the basic operation of SFAS 143 (now, which is reviewed at length in the Majority Order. Majority Order at 286-292. My focus here is on the majority's use of SFAS 143 to arrive at the conclusion that amounts expended by the Company for such tasks as dewatering surface impoundments, preparing ash for beneficiation or for disposal, excavating ash from its current storage location, transporting that ash to a new permanent disposal location onsite or offsite, and then monitoring and maintaining that permanent disposal site over an extended period of years have become "…property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within the State…," making those expenditures eligible to earn a rate of return pursuant to G.S. 62-133(b)(4) and (b)(5). I do not believe SFAS 143 leads to such a result. More importantly, if it does produce such a result, that result is in conflict with the statutory language and structure of G.S. 62-133 and cannot be accepted.

Expenditures such as those catalogued in the preceding paragraph are not in themselves "property," although they are associated with "property," that being the waste ash impoundments. For purposes of SFAS 143 accounting treatment the waste ash impoundments are "long-lived tangible assets." For purposes of G.S. 62-133(b)(1) they either are now or formerly were "property used and useful in providing service."[51] The fact that they are associated with and related to "used and useful property" does not itself make them eligible for allowance of a return computed under G.S. 62-133(b)(4). If they are properly classified as "operating expenses" for purposes of G.S. 62-133(b)(3), then they are not eligible for a return. See, e.g., State ex rel. Utilities Commission v. Public Staff N.C. Utilities Commission, 333 N.C. 195, 424 S.E.2d 133 (1993) (reasonable operating expenses must have a nexus to property used and useful in providing service, but that nexus does not render operating expenses allowable under G.S. 62-133(b)(3) eligible for a return).

How, then, do expenses that would be considered "operating expenses" under G.S. 62-133(b)(3) become transformed by SFAS 143 into "property used and useful in providing service?" I believe the core of the majority's argument is contained in the following sentence: "Recognition of the [ARO] liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired." Majority Order at 287. This statement requires careful attention, because it leads directly to what I believe is an error of law.

Under SFAS 143 when an asset retirement obligation is recognized and is recorded on the liability side of the balance sheet, of necessity there must be some corresponding and offsetting entry made on the asset side of the balance sheet. This is so because SFAS 143 is not structured such that the recognition of an asset retirement obligation, or "ARO," is meant to produce an immediate charge to retained earnings or to the equity account. The "asset side" adjustment is made by increasing the carrying cost of the long-lived asset to which the ARO relates by an amount equal to the amount of the recorded ARO liability. This increase in the balance sheet carrying value of the asset, called the "asset retirement cost" or "ARC," does not correspond to any actual increase in the value of the asset to whose book entry the ARC is added. Nothing at all has changed about the character, the qualities, the marketability, or the usefulness of the asset "…in providing the service to be rendered to the public." Likewise, nothing has changed about the "reasonable original cost of the public utility's property" embodied in that asset. The recording of the ARO liability and the capitalization of the ARC result from the change made by SFAS 143 in the timing of recognition of future cash outlays that are anticipated to be made at the time a long-lived asset is retired. The expenditures are not current outlays, but their recognition has been accelerated for financial statement presentation, and accelerated recognition must be offset by an entry on the asset side of the balance sheet.

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[51] The difference between "now" and "formerly" is quite important, and is the subject of the discussion in Part II.B., as set forth hereafter. It is not a difference that is material, however, for purposes of the present argument in this section.

From this balance sheet entry, however, the majority order concludes that because the costs associated with the closure of waste ash impoundments are now capitalized on the balance sheet, the expenditures made for those closure activities "…whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO…." Majority Order at 288. Restating the same point later, the majority says: " ...when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized." Id. at 289. The analysis in the majority order boils down to this: because SFAS 143 requires that the carrying cost of the tangible asset with which an asset retirement obligation is associated must be increased for balance sheet purposes by the amount of the asset retirement obligation when that liability is recognized and recorded, the increase in the balance sheet carrying value of the long-lived tangible asset then becomes eligible for the recovery of a return under G.S. 62-133(b)(4) and (b)(5). This is error.[52]

There are multiple difficulties with this analysis as a matter of basic statutory construction of G.S. 62-133. It is, after all, that statute that controls the ratemaking treatment of costs – of all kinds and classification -- and the determination of which elements of cost are eligible to earn a return. Most immediately, G.S. 62-133(b)(1) requires that the Commission use as its basis or starting point, "the reasonable *original* cost of the public utility's property…." (emphasis added.) The amount of a balance sheet adjustment made to the carrying value of an asset when an asset retirement obligation is recognized in accord with SFAS 143 is manifestly not part of the "original cost" of that asset. Allowing the "original cost" to be adjusted or increased because of the operation of SFAS 143 involves, quite simply, impermissibly rewriting the statute. The concept of "original cost" in G.S. 62-133(b)(1) matters, since pursuant to G.S. 62-133(b)(4), a return is allowed only on the cost of plant that has been computed in accord with G.S. 62-133(b)(1).

A second difficulty arises from considering the overall structure of G.S. 62-133(b) in the context of accounting practice and procedure as it existed at the time the statute was enacted. G.S. 62-133(b)(1) and (b)(3) adopt and incorporate in their workings the concept of "depreciation." Accumulated depreciation reduces the amount computed under subsection (b)(1), which is the amount upon which a return may be earned, and depreciation is recovered as an operating expense, without return, under subsection (b)(3). As has already been discussed at length earlier, under traditional depreciation accounting the costs that will be incurred upon retirement of a long-lived asset ("costs of removal") are incorporated into depreciation expense as part of the calculation of terminal net salvage value. In this manner, they are recovered for ratemaking purposes as an

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[52] It is also a reversal of the position taken in the Commission's August 8, 2003, Order in Docket No. E-7 sub 723. In that Order the Commission approved the Company's implementation of SFAS 143 accounting treatment for its obligations arising from decommissioning the irradiated portions of its nuclear plants and for environmental clean-up at its Belews Creek Steam Station. The Commission conditioned its approval on a number of specific qualifications and limitations, including "[t]hat no portion of the total ARO asset or liability shall be included in rate base for North Carolina retail accounting or ratemaking purposes."

operating expense pursuant to G.S. 62-133(b)(3), without a return, and not as "used and useful plant" entitled to a return.

SFAS 143 changes the time of recognition of costs of removal, in certain cases, for purposes of balance sheet presentation. It does this so that readers of financial statements may better understand expected future expenditures that will be associated with an asset.[53] Under SFAS 143 treatment the ARO and ARC entries substitute for and replace on the financial statement what had previously been shown on the financial statement as the cost of removal component of accumulated depreciation, reported as a "contra asset." Because these new entries are intended to be only a change for financial statement reporting purposes, they should be given the same treatment for ratemaking purposes as the cost of removal component of accumulated depreciation expense that they now replace. To afford any different treatment for ratemaking purposes would be, again, to allow the statutory structure and language of G.S. 62-133(b) to be amended by action of the Financial Accounting Standards Board. Whether or not such an amendment is desirable as a matter of policy, I do not believe it is within the power of the Commission to sanction it absent legislative action by the General Assembly. Because I differ with the majority and believe that under G.S. 62-133(b) the classification of costs – that is, whether they be property used and useful in providing service or whether they be operating expenses – is dispositive for purposes of eligibility to earn a rate of return, I dissent from the determination that the mere fact an item of expenditure has been reported on the financial statements as part of an asset retirement cost adjustment under SFAS 143 entitles the Company to earn a return on that expenditure.

Nor do I believe the Financial Accounting Standards Board contemplated the result arrived at by the majority here when it promulgated SFAS 143. Explaining the difference between SFAS 143 treatment and prior practice under SFAS 19, the official FASB publication promulgating the new standard explains:

> Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

With respect to the relationship between the new treatment of asset retirement obligations under SFAS 143 and the treatment of those same obligations for rate-regulated entities, the Statement explains in Paragraph 21:

> The capitalized amount of an asset retirement cost shall be included in the assessment of impairment of long-lived assets of a rate-regulated entity just as that cost is included in the assessment of impairment of long-lived assets of any other entity. FASB Statement No. 90, *Regulated Enterprises –*

[53] Statement of Financial Accounting Standards No. 143 (June 2001) pp. 4-5.

> *Accounting for Abandonments and Disallowances of Plant Costs,* applies to the asset retirement cost related to a long-lived asset of a rate-regulated entity that has been closed or abandoned.

Parsing through this language is not especially easy, but in plain English it says in substance the following: the capitalized amount of an ARO liability, i.e., the amount of the increase in the carrying cost of the long-lived asset on the asset side of the balance sheet, is to be given the same treatment as provided under SFAS 90 for a long-lived asset that has been closed. SFAS 90 is lengthy and detailed, but for present purposes the basic summary statement found in Paragraph 3 of the official statement suffices to make the point:

> When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service. The enterprise shall determine whether recovery of any allowed cost is likely to be provided with (a) full return on investment during the period from the time when abandonment becomes probable to the time when recovery is completed or (b) partial or no return on investment during that period. *That determination should focus on the facts and circumstances related to the specific abandonment and should also consider the past practice and current policies of the applicable regulatory jurisdiction on abandonment situations.*[54]

Paragraph 20 of SFAS 143 makes essentially the same point:

> Many rate-regulated entities currently provide for the costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of this Statement; others result from costs that are not within the scope of this Statement. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement and, therefore, may result in a difference in the time of recognition of period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of Statement 71 are met, a regulated entity shall also recognize a regulatory asset or liability for the differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to this Statement and rate-making purposes.

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[54] Statement of Financial Accounting Standards No. 90 (December, 1986), pp. 5-6.

Two things are noteworthy about this Statement. First, it is an explicit recognition that the treatment of costs under SFAS 143 for financial statement reporting purposes may be different than the treatment of those costs for ratemaking purposes. Second, it expressly confirms that SFAS 71 continues to apply to the accounting treatment of such differences in treatment through the mechanism of regulatory assets and regulatory liabilities.[55]

The upshot of this is that under SFAS 143, SFAS 90 and SFAS 71, which must be read together, the capitalized amount of an asset retirement cost, that is, the increase in the carrying cost of the asset equal to the amount of the ARO liability, may or may not, if it becomes an allowed cost for recovery in rates, carry a return *depending on the policies and practices applicable in a particular regulatory jurisdiction.* I read from this no intention in SFAS 143 that for a rate-regulated entity the accounting treatment of an asset retirement obligation, including the capitalization of the amount in the carrying cost of the associated asset, is to supersede or modify either the law, policy, or practice of any jurisdiction with respect to what items of cost may earn a return.[56]

Finally, I note that FERC Order 631, adopting SFAS 143 principles for entities subject to FERC jurisdiction, likewise does not compel inclusion of the capitalized amount of the asset retirement obligation in rate base; quite the contrary. Order 631, adopted on April 9, 2003, amended Title 18 of the Code of Federal Regulations to add a new section 35.18(a) that reads in full:

> A public utility that files a rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. *However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.*

(emphasis added)

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[55] It is, of course, the case that not all regulatory assets or liabilities carry with them an associated rate of return. Whether they do so or not is, once again, a function of the provisions of G.S. 62-133.

[56] In October 2002, the Edison Electric Institute and the American Gas Association issued an industry paper titled "Asset Retirement Obligations Implementation Issues." Speaking to the effect of SFAS 143 on ratemaking, the paper observes (p. 5): "Many utilities have included removal costs in depreciation rates or some other rate recovery mechanism. For ratemaking purposes, the collection of depreciation expense, including the salvage, and grow removal cost should remain intact. If customers have been paying for the cost of removal through rates, they may have a reasonable expectation that the utility will expend the costs to remove the asset at the end of its useful life."

The intent of this new rule is explained by FERC in Paragraph 62 of Order 631, which states: "To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds §§ 35.18 and 154.315 [dealing with jurisdictional natural gas entities] to its rate change filing requirements," and later in the same paragraph repeats the point, stating: "…[T]he regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment."

I therefore disagree with the majority order and would find that classification of costs and expenses – either as "used and useful property" or as "reasonable operating expenses" -- *does indeed* matter for purposes of applying G.S. 62-133(b)(4) and (b)(5). SFAS 143 does not pre-empt that choice.

B. The Four Retired Plants and Their Ash Storage and Disposal Facilities

Coal-fired generating units at four of the Company's plants were retired and were in decommissioning status at the time this rate case was filed. These include Buck units 1 through 6 (retired in 2013)[57], Dan River units 1 through 3 (retired in 2012), Riverbend units 4 through 7 (retired in 2013) and W.S. Lee units 1 through 3 (retired in 2014), and these units had been removed from plant in service. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9.) Except for the units at the W.S. Lee plant, to which CAMA does not in any event apply, the coal-fired units at all four plants were retired and decommissioning activities had commenced or were in planning stages before the enactment of CAMA; all units were retired before final adoption of the federal CCR Rule, and all were likewise retired before the entry of the Company's plea in the federal criminal cases. See Ex. Vol. 16, Part 3, pp. 175-308. None of these retired units and none of the waste ash storage and disposal units associated with them will be used to provide any future service to ratepayers of the Company. With respect to the costs for decommissioning and closure of the waste ash facilities at these four plants and independently of all other reasons for disallowance of a return discussed in this portion of my opinion, I believe the Supreme Court's decision in State ex rel. Utilities Comm'n v. Carolina Water Service*,* 335 N.C. 493, 439 S.E.2d (1994) (Carolina Water Service), prohibits allowing any return on deferred unamortized costs associated with the decommissioning and closure of the waste ash storage and disposal units at the Buck, Dan River, Riverbend and W.S. Lee plants. In the present case the costs requested for deferral and amortization for the waste coal ash facilities at these plants totals $ 392,837,165. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23).[58] For perspective, the total costs requested for deferral and amortization at all the Company's operating and retired plants totals $731,850,458, meaning that the costs associated with waste units at the retired plants comprise 53.68% of the total request. Id.[59]

[57] Buck units 1 and 2 had been retired some years earlier. Units 3 and 4 were retired in 2011 and units 5 and 6 were retired in 2013.

[58] The numbers provided by the Company in this exhibit are systemwide and do not reflect only the North Carolina retail portion.

[59] See the preceding footnote.

I am not persuaded by the majority's attempt to distinguish Carolina Water Service from the instant case. The majority attempts to diminish the holding of the case by observing that recovery of a return on retired plant was not "the major issue in the case" and that discussion of the issue occupied only two pages out of a lengthy opinion. Majority Order at fn. 64. This is pure makeweight. I submit that the holding was succinctly stated by the Court because the principle of law does not require an elaborate or extended analysis. It is next observed that the costs at issue were that portion of the original investment in the wastewater treatment plant that had not been recovered through depreciation and that in this case the costs the Company seeks to recover are new costs incurred in 2015 through 2017. Again, I believe the attempted distinction fails. As has already been discussed elsewhere in this dissenting opinion, the costs to close the waste storage and disposal units at the four retired plants are properly costs of removal to be recovered through depreciation rates as an element of terminal net salvage value. The *outlays or expenditures* for these costs may have been made in 2015 through 2017, but the *costs* – costs of removal, or depreciation expense -- were incurred and are properly allocable over the operating life of the waste facilities. In the present case, some of the coal-fired plants and associated waste ash facilities were retired earlier than their anticipated useful lives (e.g., Buck and Riverbend); others were retired at the end of their expected lives (e.g., Dan River). What matters under Carolina Water Service is that the plants and their associated waste ash facilities were not at the time this rate case was filed and never would be in service again.[60] They were not at the time of this case "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within this State…." G.S. 62-133(b)(1).

An argument has been advanced that these retired ash basins remain "used and useful" because they provide environmentally safe permanent disposal of waste ash for the protection of, among others, the Company's ratepayers. I consider this argument creative fiction. These basins contain ash residue from the burning of coal to provide electricity service to ratepayers before the retirement of the generating plants which they serviced. A fair reading of G.S 62-133(b) is to the effect that property "used and useful" upon which an investment return may be earned must be committed to the provision of utility services to present and future customers, not a prior generation of customers. I do not dispute that the costs of completing decommissioning and closure of the basins and thereafter of maintaining and monitoring them are recoverable as reasonable expenses of operation pursuant to G.S. 62-133(b)(3), but it strains common sense that they are in

[60] In Footnote 64 of the Majority Order, an effort is made to characterize the waste surface impoundments as a "class" of property for purposes of determining such matters as useful life, depreciation, and retirement from service, as if they were akin to such items as poles, conductors, and transformers. There is simply no support in the record for this attempt. The overwhelming weight of the evidence demonstrates that the ash basins were each treated and dealt with by the Company as individual units associated with their respective generating plants. The attempt to argue that they are "mass" or "class" assets on this record stands on no better ground than would an attempt to argue that all the Company's coal-fired generating units taken together constitute a single "class" for purposes of ratemaking treatment.

any respect providing the "service" to present and future customers that is contemplated by G.S. 62-133(b)(1). Moreover, I note that to the extent this argument has merit, which I do not believe it has, *even by its own terms* it can apply only to newly constructed landfills or other waste disposal units that will provide permanent storage for waste ash as part of the closure of the existing waste storage facilities. For example, surface impoundments, such as the primary and secondary ash basins at Dan River or the primary and secondary ash basins at Riverbend, or the three ash basins at Buck, all of whose waste contents will first be excavated and then removed from them before the basins are closed cannot be said to be providing thereafter any service to present or future customers.

I have also considered whether it may be the case that the ash basins at the retired generating plants may remain in use for purposes other than temporary storage of coal combustion wastes, but the record does not answer this question. Some of the Company's waste impoundments were used to treat other low-volume waste streams, from plant processes other than burning coal for the generation of electricity. During the hearing on the application the Company was asked to provide a late-filed exhibit showing the date use of each of the surface impoundments for these other waste streams ceased. From the exhibit filed by the Company an answer to this question of other use cannot be derived.[61] With the exception of the inactive ash basin at the W.S. Lee plant, the 1977 inactive ash basin at the Cliffside plant, and the primary ash basin at the Dan River plant the late-filed exhibit reported that all other ash basins at the four retired plants (Buck, Dan River, Riverbend, and W.S. Lee) were still receiving process wastewater "and/or" "stormwater (considering gravity flow as stormwater inflow)". Because the exhibit included not only the four retired plants but the four operating coal-fired plants and because it was not provided until after the close of the hearing, it is impossible to unpack this "and/or" phrase as to any individual waste impoundment. Even if it were assumed that stormwater (and groundwater, i.e., gravity flows) continues to flow into the retired ash basins, this is a function of the fact that the impoundments have not been finally covered or capped and that closure is not yet complete. It is not an indication that the impoundments will continue to be "used and useful" into the future as ongoing "stormwater treatment units." Accordingly, I find that the Company's Kerin Direct Ex. 5 (Ex. Vol. 16, Part 1, p. 10) establishes the dates of final use of the ash basins at the Buck (2013), Dan River (2012), Riverbend (2014), and W.S. Lee (2014) plants.[62] Those dates all precede the filing of this case.

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[61] Pursuant to a request I made on the record during the evidentiary hearing, the Company, through its counsel, filed this late-filed exhibit on April 2, 2018, containing a spreadsheet containing the information discussed here.

[62] These dates are identified on the exhibit as dates basins were "closed," but witness Kerin explained that this does not refer to closure for regulatory purposes but the date the impoundment ceased receiving wastes for treatment and storage. Tr. Vol. 16, pp. 43-47.

C. All Plants – Separating Sheep from Goats

The argument in the prior section applies only to those waste ash facilities at the coal-fired plants that were retired prior to 2015.[63] In this section I address issues that arise in the case of all plants, operating and retired. Proper characterization of the costs the Company is seeking to recover for ash basin closure activities at its plants is essential for application of the ratemaking provisions in G.S. 62-133(b). On the record in this case that is a difficult, if not in part impossible, assignment. Part of the difficulty is a function of the different stages in which the closure process now stands at each of its plants and for each of the waste ash units and the different rates at which closure activities are progressing. Another part is the difficulty of reconciling the listing of the tasks for which cost recovery is sought in this case with historical documentation of ash basin closure tasks already undertaken by the Company in periods prior to 2015, the first year for which cost recovery is being requested in this case. Yet a third portion of the difficulty is the opaqueness of the task descriptions in the pertinent exhibits and evidentiary submissions themselves.

Kerin Direct Exhibits 10 (Ex. Vol. 16, Part 1, pp. 22-23) and 11 (Revised Kerin Ex. 11, filed by DEC on March 22, 2018) are the core exhibits summarizing the request for cost recovery in this case. For each of the retired and operating plants, Exhibit 11 sets out a summary of categories of expenditures, both actual for 2015, 2016 and 2017, and forecast for later years. I use the portion of Exhibit 11 that speaks to the Allen plant, an operating plant, for illustration. The categories fall into two groups. The first group includes: (1) mobilization and site preparation, (2) site infrastructure, (3) water treatment & management, (4) ash processing, (5) construct landfill & cap-in-place, (6) site restoration, demobilization, closing, (7) engineering closure plans, (8) a category designated as "Duke Cost," (9) site maintenance landfill, etc., and (10) contingency. These ten categories of costs are grouped together in a summary subtotal titled "Basin Closure." A second group of items consists of a group of eight other categories of costs, including (1) CCP[64] basin support projects, (2) CCP oversight & LRP, (3) CCP inspections and maintenance, (4) CCP engineering, (5) EHS, (6) post-closure maintenance, (7) previous landfill ARO cash flows, and (8) inflation impacts.

[63] The position I have taken with respect to the closed generating units could be extended to include the former ash impoundments at the four operating coal-fired plants – Allen, Belews Creek, Cliffside, and Marshall -- that were removed from service long in the past. These would include the 1957 ash impoundment at the Allen plant, which was closed in 1973 and the 1957 and 1970 ash basins at the Cliffside plant, which were closed in 1977 and 1980, respectively. This is in fact the position I adopted in dissent in the DEP Rate Case Order. The Company advised, in response to a question on the point, that it could not present a separate accounting for closed or inactive impoundments apart from the closure costs incurred and expected to be incurred for the remaining active impoundments. Tr. Vol. 16, p. 52; DEC Response to Commission Request Regarding ARO, filed April 6, 2018. While witness Garrett was able to obtain some separate data for the inactive ash basin and the borrow area at the retired W.S. Lee plant, the same level of detail is not present in the record for the retired basins at any of the operating plants.

[64] "CCP" is shorthand reference for "coal combustion products," otherwise known as wastes left from burning coal.

Page 8 of Kerin Direct Exhibit 11 contains footnotes for these categories, but it provides only marginally more information than the titles of the categories themselves suggest. A number of the categories can be understood from the testimony of witness Kerin or other witnesses in the case. For example, "CCP inspections and maintenance" appears to refer to ongoing maintenance activities relative to the surface impoundments, including such tasks as maintaining the integrity of dikes and dams, preventing vegetation encroachment, maintaining risers and discharge piping, and similar. "EHS" appears to refer to an allocation of the costs for the Company's general Environmental Health and Safety department, but the footnote suggests that it also includes "well installation, well sampling (groundwater monitoring), bottled water and permanent water supplies provided to nearby residents." "Construct landfill & cap-in-place" is fairly straightforward; it captures the costs to construct a new permitted landfill or to cap-in-place an existing unit. The categories titled "water treatment and management" and "ash processing," based on the testimony of witnesses Kerin, Garrett, Moore, and Wells, likely involves dewatering of ash in an impoundment, consolidating the ash and preparing it for removal, excavation of the ash, and transport to another location for final disposal. The category "inflation impacts" shows the expected increase in costs for tasks that will not be undertaken until later years in the period covered by the exhibit (2015 through 2057). Other categories are more opaque. For example, how do the tasks embraced within the category "CCP Basin Support Projects" differ from those in such categories as "CCP Oversight and LRP," or "CCP Engineering," or for that matter, what is included in "CCP Engineering" that is not included in "Engineering Closure Plans"? Finally, other categories, most notably the one titled "Duke Cost" remain a complete mystery; all that can be said with any certainty is that it represents costs that do not fall within one of the other enumerated categories.

I am mindful of the principle that we take the amounts recorded in the Company's books as they are given and do not look behind them unless a specific challenge is made to some item of expense or revenue.[65] The issue here presented, though, does not involve questioning the amounts reflected on Kerin Direct Exhibits 10 and 11 but rather deciding, for ratemaking purposes, which of those amounts represent investments for which the Company may earn a return and, on the other hand, those which are in the nature of expenses of operation and maintenance. Even within the first grouping of expenditure categories, those summarized as "Basin Closure," proper characterization is somewhat difficult. "Water treatment and Management" appears to refer to the process of decanting standing water and dewatering the ash in the basin. "Ash Processing" appears to refer to consolidation and stacking of the dewatered ash in order to reduce the area footprint that will require capping and vegetation or, if the ash is to be excavated, consolidating it for more efficient transport, or perhaps treating it for purposes of beneficiation.

[65] Agreeing with the Company's proffer, Public Staff witness Moore testified that based on his review of the costs incurred in 2015, 2016 and 2017 for the ash basins at the four operating plants -- Allen, Cliffside, Belews Creek, and Marshall -- were reasonable and prudent, and I am not contesting this judgment. Again, the issue is how those costs should be characterized for ratemaking purposes.

From the available evidence I conclude that the costs for which recovery is sought in this case include a significant mixture of costs that are correctly characterized as operating and maintenance expense, and another portion that might be considered investment in capital assets required for basin closure. In the case of the Allen plant, which I have used as an illustration, most of the expenditures for the years 2015, 2016 and 2017 are recorded in categories that appear more appropriately considered operating and maintenance expenses, especially since the ash basin at the Allen plant remains active and actual closure has not yet commenced. For example, during the period 2015 through 2017, none of the costs incurred at the Allen plant have been for such activities as "mobilization and site preparation," "site infrastructure," "ash processing," "construct landfill & cap-in-place" or "site restoration, demobilization and closing," which are categories that it might be argued are capital in nature and potentially eligible for a return. For 2015 and 2016, of the total requested cost recovery of $32,663,754, some $28,908,681 is recorded in the categories "EHS," "CCP oversight and long range planning," and "CCP basin support projects." Only $3,755,073 is recorded in the large subgroup of categories headed "Basin Closure," and of this total $2,457,590 (or 65.45% of the total) falls within the mysterious category labelled "Duke Cost."[66]

The problem can also be illustrated by a different example. For the period 2015 through 2017, the period for which cost recovery or deferral and amortization are sought in this case, total costs incurred for closure activities at the Dan River Steam Station were $143,237,755, and total costs incurred for closure activities at the Riverbend Steam Station were $220,273,249. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23.)[67] These are the two sites ranked high priority under CAMA, and together these two plants account for 49.67% -- just under one-half -- of the Company's total expenditures on all its waste ash storage and disposal facilities during the period. Based on the information that can be extracted from Revised Kerin Direct Ex. 11 (filed by DEC on March 22, 2018), interpreted in light of witness Kerin's testimony, the testimony of witnesses Garrett and Moore, and documentary exhibits, the principal activities conducted at these two plants included excavation, transport and offsite disposal of ash fill area 1 at the Dan River plant, dewatering ash in the primary and secondary surface impoundments at Dan River, excavation and transport of ash from the ash stack at the Riverbend plant to Roanoke Cement Company and the Brickhaven mine, dewatering the primary and secondary ash basins at the Riverbend plant, and beginning excavation and transport of ash from the primary and secondary ash basins at the Riverbend plant for offsite disposal. I do not believe these activities can be under any reasonable interpretation of G.S. 62-133(b)(1) considered investments in plant or facilities used or useful to provide electric service to present and future customers.[68] They are under any common understanding of the terms, expenses of operating and maintaining the (retired) coal-fired generating plants.

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[66] In this example I do not include the figures for 2017, since they are projected numbers on Kerin Ex. 11.

[67] The data in this exhibit were presented on a systemwide basis and do not represent the North Carolina retail allocation. For present purposes, however, that point is not material.

[68] The Company plainly knows how to characterize an expenditure as "capital" versus "operating." On Kerin Direct Ex. 11, the costs to purchase the equipment necessary for preparing ash excavated from

I use this second example because the elements of cost involved are fairly straightforward and are, on this record, a very large proportion of the total expenditures for which recovery is being allowed by way of deferral and amortization. The point of all the foregoing is that the assumption made in the majority order that *all* of the costs incurred and yet to be incurred are "assets" or are "investments" that are "used and useful" simply cannot withstand a more granular examination and consideration of the specific items of cost and their nature. I believe it is error to conclude that simply because the costs incurred by the Company relate, in some manner, to present or former waste surface impoundments, they therefore constitute expenditures or investments for which a return is authorized by G.S. 162-133(b)(1). Sorting out those costs that represent an investment in "used and useful" plant and equipment from costs that represent either ordinary or extraordinary expenses of operation requires a plant-by-plant, waste unit-by-waste-unit, task-by-task inquiry and evaluation.[69] This the Majority Order does not do, instead lumping all tasks, all waste units, all time periods, and all plants together and allowing a return on the expenditures without further qualification, except only the reduction of that return by $70 million. I further believe that this outcome is largely the result of the erroneous determination that it is unnecessary to engage any such exercise because of the Company's adoption of SFAS 143 accounting for its coal ash expenditures. the Even if the Commission has discretionary authority to allow a return on the unamortized portion of the amounts expended from 2015 through 2017, I do not believe its exercise of that discretion in such an undifferentiated and summary fashion is proper.

D. Working Capital …. or Not?

As did its affiliate in the DEP Rate Case, the Company here attempts to argue that its expenditures for closure of the waste ash impoundments have been financed from shareholder funds provided for working capital and that they are therefore eligible for a return under the holding in State ex rel. Utilities Comm'n v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO). I note that the Company's presentation of evidence on this point differs in no material way from the presentation made by its affiliate in the DEP Rate Case, and I find it no more persuasive here than in that proceeding. The calculation of working capital set forth in witness Doss Direct Ex. 2 (Ex. Vol. 12, p. 786) contains no amounts designated as needed for additional working capital due to coal ash costs, and the Company's position I believe rests on nothing more than an *ipse dixit*.

In this case I find in the evidence an additional reason for rejecting the Company's position. As the Court made clear in VEPCO, not all funds that are functionally used as

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the impoundments at the Buck Steam Station for beneficial reuse is specifically denominated in a separate category titled "Capex – Equipment and Facility Cost."

[69] This is not an impossible task. It is one the Company knows very well how to perform. For example, in its 2008 Coal Combustion Products Ten-Year Plan, Kerin Public Staff Ex. 2, Vol. 16, Part 1, p. 47 and *passim*, the Company prepared elaborate budgets for planned expenditures for its coal ash storage and disposal facilities, classifying those expenditures as either "Capital," "O&M," or "Risk," the latter term possibly referring to the "risk" that they might not be recoverable in rates.

working capital are investor provided funds on which a return may be allowed; funds provided by ratepayers to cover anticipated expenditures not yet incurred may be used by the Company in the interim as working capital, and such funds are not eligible for a return. Id. at 415, 206 S.E.2d at 293.

Due to the enactment of the Federal Tax Cuts and Jobs Act of 2017 the evidence shows that the Company has collected from ratepayers an amount presently estimated to be in the order of $953 million in unprotected EDIT that it will not now be required to pay to the federal government in taxes. (Revised McManeus Workpapers, Schedule 1-4, Line 2, Column (b), and Schedule 1-5, Line 8, filed by DEC on April 19, 2018.) This amount must now be returned to ratepayers. In the Matter of Tax Reform Act of 1986, Docket No. M-100, Sub 113, 82 P.U.R.4th 234, 234-35 (Oct. 23, 1986), aff'd, State ex. rel. Utilities Comm'n v. Nantahala, 326 N.C. 190, 197, 388 S.E.2d 118, 122 (1990). In the interim, these funds represent precisely the type of "ratepayer provided working capital" about which the VEPCO court spoke.

The final number of such excess deferred income taxes will be refined as the Company does further analysis of the actual effect of the new tax legislation. Because this development occurred after the test year for this case, after the rate case was filed, and on the eve of the hearings on the Company's application, the Commission has concluded that disposition of this excess amount collected from ratepayers in anticipation of taxes that will now not be paid should be deferred until the Company's next general rate case and placed in a regulatory liability account in the interim. I support this disposition. For present purposes, however, the important fact is that the Company will have the use of these ratepayer provided funds as "working capital" until such time as they are returned to ratepayers in the manner provided in the Company's next general rate case. The final amount, even after refinement, will be substantial, and I find it impossible on this record to conclude that in order to finance its costs to close its waste coal ash impoundments between now and the time of its next general rate case the Company either has been or will be, in the near term, using shareholder provided funds instead of or to the exclusion of ratepayer funds such as the amount represented by this regulatory liability item.

E. A Final Matter of Policy

Ash wastes are a residue from the burning of coal to generate electricity. Supplying electricity is the service for which the Company is entitled to compensation, and the investments it makes in plant and facilities in order to supply that service are the capital assets on which it is entitled to earn a return. There is no dispute that the cost of the coal burned is an operating expense incurred in order to deploy those capital assets to provide electric service. It stands this paradigm on its head to allow the Company to treat the residue from this fuel as a new opportunity for capital investment and for profit-making. The fuel itself has real value for the provision of a desired service, electricity; surely the unwanted residue, except when committed to beneficial reuse, has no such value. Yet under the majority's analysis, the residue has now become of greater profit-making value to the Company than the underlying fuel itself. We are in the waning years of the Company's use of coal as a fuel, but even so the Allen, Marshall, and Cliffside coal-burning units will continue to consume prodigious quantities of coal for over a decade to come. The cost of that coal will be reliably recovered, without profit, in the Company's general rates and through the fuel adjustment rider. What the majority does today, however, creates an undesirable incentive with respect to the use of that coal. Different coals burn with different degrees of efficiency and generate different quantities and qualities of waste as per unit of coal burned. Is there now to be an opportunity for earning an increased profit by purchasing lower quality coal or coal that leaves more residue or residue more expensive to manage, thereby generating higher disposal costs when the ash basins at the still-operating plants are finally retired? These costs will form the basis upon which additional profit may be earned. This is an unacceptable and even absurd result, and I do not suggest that the Company would intentionally pursue such a course. However, this "thought exercise" illustrates the type of error into which I believe the majority has fallen by allowing recovery of a return on the deferred costs of permanently disposing of the waste ash. I believe the General Assembly in Chapter 62 intended to provide an opportunity for companies to earn a return on the provision of a valuable service – electricity. It did not intend to establish that scheme in order to encourage investment in waste management enterprises.

In summary and for all the foregoing reasons I find that on the present record the deferred portion of allowed costs attributable to closure of the waste ash storage and disposal facilities are ineligible for allowance of a rate of return. It is not necessary for me to say anything further about the "mismanagement penalty" assessed in the Majority Order because there is nothing to which that "penalty" attaches.

III. Increase in Basic Facilities Charge (BFC) and its Applicability Only to the Residential Class of Ratepayers

The majority's decision to permit an increase in the fixed monthly billing charge for residential rate classes, but not for any of the other customer rate classifications, I consider one of the more peculiar aspects of the decision, and I dissent from that portion of the findings and order that authorizes the increase. While in the final outcome the Commission has determined that the Company's revenue requirement should be reduced, and I concur generally in that result, although based on issues discussed in this dissent, I would find and am of the opinion that the revenue requirement should be lower than that determined by the Commission majority. Despite the evidence and issues addressed elsewhere in this dissenting opinion which support a further reduced revenue requirement, the majority approves an increase in the fixed monthly charge affecting only the residential customers.

The majority does not support its determination with any findings or evidence showing that the Company's fixed costs to serve residential customers has increased over what is supported by the revenues upon which the Company's present rates are based. It does not make findings or point to any evidence that the fixed costs to serve residential customers have increased relative to costs of service for non-residential customers. While not granting the full amount of increase requested by the Company for the residential rate class, the majority rejects altogether the Company's request for an increase in the fixed monthly charges applicable to non-residential rate classes, without offering a compelling reason, nor a reason which is supported by the record in this case, for such different treatment. I acknowledge that these observations are all about cost of service and that the matter of setting the fixed monthly component of rates is a matter of rate design. However, if there is no demonstrated need for additional revenue to be provided from residential ratepayers, other justifications for the increase must be found. Moreover, to support such a difference in treatment between the residential and non-residential classes, there must be justifications peculiar to the residential rate classes and not applicable to the non-residential rate classes. I believe the majority's justifications, to the extent they are articulated at all, are without basis in the record.

The only grounds of justification for the increase in the residential fixed charge portion of the residential rates to be gleaned from the majority order are 1) the unsupported easing of subsidization between members of the residential class and 2) the acceptance of the Company's assertion that, based on the "minimum system" method for the allocation of the customer portion of distribution plant costs, the present residential monthly fixed charge is lower than the actual fixed charge caused by the residential class of customers. Dealing with the grounds separately, the majority's subsidization justification for increasing the fixed monthly charge for residential customers is set forth in a single sentence:

> The increase in these schedules minimizes subsidization and provides more appropriate price signals to customers in the rate class, while also moderating the impact of such increase on low-income customers to the extent that they are high-usage customers such as those residing in poorly insulated manufactured homes.

Majority Order at 112. That is it; all else is based on alleged cost causation, i.e., that the current fixed charge does not accurately reflect the Company's fixed costs of serving residential customers. The "subsidization" referred to here is alleged subsidization by high usage customers of the low usage customers, the latter category including, among others, customers who have aggressively implemented energy efficient measures and may even be self-generating a portion of their own electricity needs. A contrast is drawn between these low usage customers and the high usage customers, such as "those residing in poorly insulated manufactured homes," who are allegedly subsidizing the low use customers through energy charges artificially inflated by a fixed charge that is too low. The difficulty with this picture is that it is conclusory and simply without evidentiary support in the record. Indeed, the only evidence offered by any party in an attempt to characterize who are the "low users" and who are the "high users" was offered by NC Justice Center, et al. witness Howat, whose evidence was to the effect that the population of low-use customers tends to have a higher proportion of low-income, elderly, and African-American ratepayers; not that low income customers reside in poorly insulated homes or are high energy users as asserted by the majority. It is not necessary to decide for the present whether Howat's evidence is correct, only to point out that the majority has no evidence to support any contrary picture or the majority's stated (stereotypical) presumption that low income customers are high energy users subsidizing low energy users.[70]

This then leaves the majority with only its "cost causation" justification for the increase in the residential fixed charge. As I have already noted, the Commission in prior rate orders has recognized that cost allocation and rate design are separate topics, and the parties continue to pay homage, at least in principle, to this distinction. Nonetheless, with respect to setting the fixed component of monthly customer bills, a matter of rate design, it is apparent that the positions of the contending parties are largely determined by their views concerning the propriety of using the so-called minimum system method for allocating the customer portion of distribution plant costs. In past rate cases the Commission has permitted the Company to use the minimum system method for purposes of deriving the customer portion of embedded distribution system costs, but it has expressly stated that the results yielded by that method do not and should not dictate the level of the per customer fixed monthly charge. <u>See, e.g.</u>, Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30. Moreover, there are other considerations, aside from costs, that go into rate design, including setting the fixed charge portion of the rate. <u>See</u> DEP Rate Case Order at 107-08, 114 (acknowledging that factors other than cost of service are appropriate to consider and balance in rate design). In the present case the majority takes the further positive step of directing the Public Staff to initiate discussions with the regulated electric utilities to explore in greater depth the use of the minimum system method and alternative methods for allocating distribution system costs and to submit a report to the Commission by March 31, 2019.[71]

For myself, while I will consider the report and any other evidence that may be properly introduced, I am concerned that the time has come or may have come to divorce, explicitly and completely, the setting of the fixed monthly charge from any association with the minimum system methodology used for allocating embedded distribution system costs. It may be that the minimum system method should be rejected entirely as both a tool for cost allocation and, as a necessary consequence, as an indirect determinant of the per customer fixed monthly charge.[72] The reasons for abandoning use of the minimum system method have been ably briefed by several of the intervenors, including

[70] Moreover, if the majority's expressed concerns about subsidization are legitimate, the Company's request in this general rate case to increase the fixed charge portion of the rate applicable to the non-residential classes would indicate that the current non-residential rates are not properly balanced between fixed charges and demand charges, and the Commission should have the same interclass subsidization concerns with respect to non-residential customers. However, the majority discriminatorily disregards, without explanation or justification, the issue of subsidy for all but the residential class of customers and does not impose any fixed charge increase on nonresidential customers to ease the impact of alleged subsidization.

[71] Part of the majority's rationale for taking this step relies on language taken from my dissent in the DEP Rate Case. Based on continued study of the issue since that time and the additional evidence taken in this case, my position has now become more firm on the subject, especially in light of the result in this case concerning the residential fixed monthly charge.

[72] I would do this for all customer classes, not just the residential rate classes.

NCSEA and the NC Justice Center, et al., and are powerfully supported by the testimony of witnesses Barnes and Wallach. The Company's defense of the minimum system method rests almost entirely on history and custom, supplemented by the fact that the minimum system is one among several recognized methods for allocating the embedded costs of distribution system plant and facilities among rate classes. Tr. Vol. 19, pp.34-35.

The method has been persuasively condemned on conceptual grounds, one of the more notable critics being Professor Bonbright, who in his 1961 treatise observed:

> [T]he really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers. What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 347-348 (1961).

This objection is reinforced by the fact that the methodology's stated purpose -- to allocate those embedded distribution system costs that are a direct function of the number of customers served by the distribution system -- is one that is difficult to realize in practice with any reasonable degree of faithfulness to the nominal principle behind the method. I find the report[73] prepared by Frederick Weston (The Regulatory Assistance Project), cited by NCSEA witness Barnes, to be most informative on this subject. Weston notes in his Executive Summary that "The distribution network is no longer the seemingly static

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[73] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

monopoly that it once was. The policies that regulators adopt should be devised with an eye to competitive service provision, to encourage innovative and environmentally sustainable energy use. They should not shortsightedly protect a status quo that, over the coming decades, will not be well-suited to the economy it serves."[74] Further, Weston states that "There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature; marginal, embedded, fixed, variable, joint, common, etc. and thus on how they should be recovered in rates."[75]

The Company implicitly acknowledges this problem when it concedes that its actual application of the minimum system concept is a modification or variation of the pure principle. See Tr. Vol. 19, pp. 38-39. I do not agree with the majority's opinion that the minimum system analysis employed by the Company is not flawed in a way that makes it inappropriate for cost allocation in this proceeding. Rather, the critiques offered by NCSEA and NC Justice Center, et al., in their post-hearing briefs, and the testimony of witness Barnes, in particular, are compelling. In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment of these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[76] The negative

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[74] Id. at 5.

[75] Id. at 28.

[76] DEC Form E-1, Item 45D, p. 5.

values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer unit costs. Tr. Vol. 20, pp. 82-83. These detailed objections to the Company's practical application of the method in practice are not effectively rebutted by the Company, and this in itself is some confirmation of a large degree of subjectivity in how the method is applied to a real world distribution system.

If the minimum system method is inappropriate for assignment of the customer portion of distribution system costs among the several customer classes, then what is to replace it? Here I suggest that a defensible method, and the one that is most widely used by other regulatory authorities, is perhaps to use a per customer allocator only for those costs directly attributable to the addition of another customer to the distribution grid – the cost of the customer meter, the service drop, and any other facilities uniquely attributable to a specific customer. All other distribution system costs, including poles, transformers, and conductors, would use a demand allocator entirely. This is the so-called "basic customer method" well-recognized and widely used as an alternative to fixed charges that are designed to reflect output from the minimum system method of cost allocation. The Commission's Order acknowledges this by recognizing the testimony of witness Barnes and specific reference to Mr. Weston's report, which states that "There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states."[77] Tr. Vol. 20, p. 79.

Shared distribution plant and facilities, whose cost would be assigned using a demand allocator, are those actually installed by the Company to meet real world expected demand and maintain service reliability. Put differently, excluding only the marginal costs directly attributable to the addition of another customer, the system whose costs must be recovered is not sized to meet some "phantom" level of demand but instead is sized to meet actual historical and projected system demand. It is the costs of this real world system that must be allocated, and those costs are heavily driven by demand.

Turning back to the topic of the fixed monthly charge, if the minimum system method is not used for distribution system cost allocation purposes, what, then, is? What, then, are the proper determinants of that component of the customer's bill? I believe we perhaps should answer that question in the same way the majority of other jurisdictions do: the monthly fixed charge should reflect the cost for the service drop, the meter, any other facilities uniquely deployed to connect a customer to the system, to

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[77] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

which would be added an allocation of the administrative support costs of meter reading, billing, collections, and customer service.

Given the concerns and issues presented by use of the minimum system methodology, I think that the Company's fixed monthly charges for the several customer rate classes likely already equal or even exceed the level that would be arrived at using the "basic customer method" for cost allocation purposes and the principle of cost causation for purposes of rate design. For example, the current BFC for the residential rate schedule RS is $11.80, whereas the unit cost without minimum system is calculated to be $11.08. See Tr. Vol. 20, p. 77; Pirro Direct Testimony Exhibit 8.

I also note that once the distraction of the minimum system method is removed from consideration, other arguments used to support a higher monthly fixed charge take on a new aspect. As has been stated already, proponents of increasing the fixed charge rely largely on the results of the minimum system method and the principle of cost causation, but they supplement their positions by noting that a fixed monthly charge that is set at a level lower than the fully distributed per customer costs derived from using the minimum system also results in overcompensating for energy efficiency and distributed generation. It does this, they say, by artificially increasing the energy charge component of customer rates. However, once we conclude that the Company's current fixed monthly charge already fully compensates for properly allocated fixed customer costs, using the "basic customer method," then the issue of overcompensation or undercompensation for energy efficiency and distributed generation falls away. This is so because so long as the Company's fixed monthly residential customer charge fully covers the properly allocated customer portion of its costs, the remainder of the established rate will reflect only the demand and energy costs allocable to that customer class.

If, as I believe the evidence clearly shows, the Company's current fixed monthly charge for residential customers already covers its fixed costs were the basic customer method of cost allocation used, then certain other issues that occupy the majority's attention would also disappear. The majority expresses concern about internal subsidization within the residential rate classes when fixed costs are apportioned to the energy rate, thereby penalizing high usage customers and benefitting lower usage customers. But again, if the existing fixed monthly charge is already set at a level that compensates the Company for its fixed per-customer costs, using a method other than the deeply flawed minimum system, no such subsidization is occurring.

The one virtue of a high fixed charge component of bills is that it improves revenue stability for the Company; the higher the fixed component, the more stable revenues will be. While this is not an unimportant consideration, it does not outweigh the conceptual flaws and difficulties in execution involved in the minimum system method. There are other, and in my view better, methods for addressing the utility's need for stable revenues. I am optimistic that the Public Staff and utilities' pending work to further evaluate use of the minimum system method and alternative methods for allocating distribution will "bear fruit" and appropriately inform future decisions. In this regard, I concur with Mr. Weston's admonition in his report, to be practical. He further states that:

> [T]here is the designation of a cost as either customer or demand, which will affect both how costs are divvied up among classes and who within each class will pay them (i.e., both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system's costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough.

F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

Finally, I take note of the fact that the evidence before the Commission in this case concerning the Company's proposed Power Forward initiative and its associated request for a cost recovery rider provides additional grounds that would tend to support rejecting the minimum system method as a means for assigning distribution plant costs to the several customer classes. In response to a question posed at the hearing concerning the impact, if any, of the planned targeted undergrounding investments on the application and output of the Company's minimum system method, the Company offered the following explanation in a post-hearing submission. Currently, underground distribution facilities are not considered by the Company to be part of a "minimum system," since they are considered non-standard installations. As a result of the Company's proposed Targeted Undergrounding Program, this would change, and underground installations will then be considered components of a "minimum system." See DEC Late-Filed Exhibit Regarding Planned Change to Minimum System Methodology (April 6, 2018). Because, subject to variation and exceptions, underground plant is generally more costly than overhead facilities, this would result in a greater total distribution plant cost assigned to each of the customer classes than is presently the case. Further, because the residential rate class has by far the most numerous membership, most of this additional "minimum system" cost would very largely fall on that class. Not surprisingly, this will almost certainly mean that in future rate cases the Company will contend that its per customer cost of service, derived in part from application of the minimum system method, is even higher than it is today, thereby warranting a further increase in the fixed monthly per customer charge. Most likely, this same result will obtain with respect to some other elements of the Power Forward investments, such as the creation of distribution system redundancies that will be necessary to support a self-optimizing and self-correcting distribution system.

The theoretical objections to the minimum system methodology are even more apt in the case of the proposed Power Forward investments. Correlation between the need for underground plant and the number of customers on the system is vanishingly weak; as explained by the Company, the need for underground distribution plant is instead driven by the density, age, and condition of vegetation and by animal and bird populations along distribution lines. The purpose of undergrounding plant is to protect the distribution system from service interruptions, a demand-related concept, and is not dependent on the number of customers whose aggregate demand is at risk of interruption. I find it difficult to consider these investments to be part of a "minimum system." Certainly, they may improve the reliability and resilience of the distribution grid, but these are enhancements to a "minimum system," not elements of it. The point here is that what constitutes a "minimum system" for purpose of cost allocation among customer classes requires the exercise of judgment; it is not something that is self-evident. In my judgment, including the types of distribution plant upgrades that are contemplated by the Power Forward system in the "minimum system" strays too far from the theoretical justification that supports use of the minimum system methodology.

I recognize that the majority is not yet prepared to move to the basic method over the minimum system method in spite of the implications for the fixed monthly charge. Nonetheless, in light of the legitimate issues raised with respect to the minimum system method and the Commission's decision that these issues are sufficient to warrant greater in depth investigation, I believe the counsel of prudence would be to leave the current level of the fixed monthly charges in place pending that consideration, especially in light of the lack of any need for additional revenue. That is an outcome I could have supported; I do not support increasing the residential fixed monthly charge by $2.20 per month.

IV. Cost-Effectiveness and Prudence of Advanced Metering Infrastructure (AMI)

The majority approves DEC's request to recover its costs of replacing Advanced Meter Reading (AMR) meters with AMI, and DEC's recovery of the remaining book value of its AMR meters. The majority reasons that DEC's AMI costs are reasonable, and that DEC's decision to replace its AMR meters with AMI was prudent. I do not question the reasonableness of DEC's AMI costs. However, based on the evidence I conclude that DEC's deployment of AMI is not cost-effective and, largely as a result of that lack of cost-effectiveness, DEC's decision to deploy AMI was not prudent. Therefore, I would deny DEC's request to recover its AMI costs in this proceeding, but allow DEC to defer those costs, with no carrying charge, until a future general rate case in which DEC produces substantial evidence that AMI is cost-effective.

A. DEC's Failure to Comply with Rule R8-60.1

The Majority Order includes the details of the pertinent proceedings under Commission Rule R8-60.1, the rule on smart grid technology plans. In addition, the following segment from the Commission's March 29, 2017 Order Accepting Smart Grid Technology Plans (SGTP Order), in Docket No. E-100, Sub 147, is of note. After citing several requirements of Commission Rule R8-60.1 with respect to the information to be provided by the electric utilities for smart grid technologies currently being deployed or scheduled for implementation within the next five years, the Commission stated:

> [t]he Commission notes that neither DEC, DEP nor DNCP included the above information in their 2016 SGTPs with regard to any future plans for deployment of AMI meters. The Commission interprets this to mean that DEC, DEP and DNCP currently have no plans to replace existing meters with AMI meters, either incrementally or on full scale, during the next five years. As a result, the Commission expects DEC, DEP and DNCP to provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters.

SGTP Order, p. 17.

Commission Rule R8-60.1(c)(3) requires the electric utilities to provide the Commission with a cost-benefit analysis and other detailed information about smart grid technologies currently being deployed by the utilities or scheduled for implementation within the next five years. One purpose of the rule is to allow the Commission, Public Staff and other interested parties to review information about proposed smart grid programs, request additional information when needed, and have input regarding the implementation of smart grid programs well in advance of their implementation. Smart grid technologies are relatively new and evolving projects that require substantial capital investments. Therefore, the public interest is best served by the Commission and parties having sufficient time to study and understand the details of a smart grid project before it is launched. DEC appears to support this purpose. In his rebuttal testimony, in response to EDF witness Alvarez's recommendation that the Commission review DEC's AMI project in a separate docket, witness Schneider testified:

> [T]he Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of other utilities.

Tr. Vol. 18, p. 342.

Notwithstanding DEC's understanding of and appreciation for the Commission's SGTP rule, as noted above DEC did not provide a cost-benefit analysis and other required information in its 2016 SGTP to support an AMI deployment. Consequently, the Commission directed DEC "[t]o provide the Commission with the above information, as well as any other required information, in their SGTP filings <u>prior to implementing an incremental or full scale effort</u> to replace existing meters with AMI meters." SGTP Order, at p. 17 [emphasis added] Nevertheless, DEC, as it stated in its May 5, 2017 supplemental filing, began deploying AMI meters "in early 2017." Thus, DEC began its deployment of AMI before complying with the requirement to file the cost-benefit analysis and other information required by Commission Rule R8-60.1, and in contradiction to the Commission's 2016 SGTP Order.

The Commission, by its SGTP Order issued on March 29, 2017, accepted DEC's 2016 SGTP as originally filed. In its May 5, 2017 supplemental filing, DEC stated that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, even though DEC had stated in its 2016 SGTP, filed on October 3, 2016, that it was studying whether to implement AMI. DEC's decision to begin a full scale AMI deployment "in late 2016" must have been made in November or December of 2016. Further, DEC stated in its supplemental filing that it began deploying AMI meters "in early 2017." Yet DEC waited until May 5, 2017, to inform the Commission of its decision to begin AMI deployment and its implementation of that decision. DEC's May 5, 2017 supplemental filing was a substantial amendment to its 2016 SGTP. DEC did not request that the Commission issue an order accepting its amended 2016 SGTP. More importantly, the Commission did not issue an order accepting DEC's amended 2016 SGTP.

Based on the foregoing, I conclude that DEC failed to comply with the letter and the spirit of Commission Rule R8-60.1. The result was that DEC defeated the ability of the Commission, Public Staff and other interested parties to provide advance input regarding the implementation of AMI. Instead, DEC made the decision to deploy AMI and began implementing that decision without informing the Commission and obtaining the Commission's acceptance of that significant revision to DEC's 2016 SGTP. To be clear, I do not base my denial of DEC's AMI cost recovery on its failure to comply with Rule R8-60.1. However, I do find it important in providing context to my analysis.

B. <u>Cost-Effectiveness of DEC's AMI</u>

In DEC's supplemental information filing on May 5, 2017, in the SGTP Docket, DEC stated that it would be replacing approximately 1.32 million AMR meters from 2017 through 2019. (Supplemental Filing, p. 2) In the AMI cost-benefit analysis filed by DEC as a part of its supplemental filing, DEC concluded that its AMI deployment would result in net benefits having a present value of $117.1 million. (Supplemental Filing, Exhibit No. 2) The largest category of benefits included in the analysis is entitled "Non-technical line loss reduction - power theft, equipment failures and installation errors" (NLLR). It is the last column of benefits shown on Exhibit No. 2, and totals $634.8 million. In comparison, the next largest category of benefits is "Reduced meter operations costs – consumer order workers for meter orders," a total of $175.4 million. According to the cost-benefit analysis, the total of the AMI benefits is $1.007 billion. Thus, the NLLR portion of the benefits is 63% of the total.

In response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated, in pertinent part:

> According to a 2008 EPRI report, industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. This assumption was utilized in calculating the DEC AMI benefits.

DEC's First Responses, p. 5.

During DEC's SGTP presentation, DEC witness Schneider was asked whether EPRI or any other entity performed a physical real world study to verify the 2% NLLR figure. Witness Schneider responded:

> Not to my knowledge. I think they went on data. Again, this was a report, not necessarily a study but it was a report, and they were going off of other reports and studies going back years and years that came up with this on average 2 percent of gross revenues so they did not.

SGTP Presentation, Tr., p. 40.

Witness Schneider also stated that DEC has not performed a study that confirms the 2% NLLR factor reported by EPRI. In addition, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025. SGTP Presentation, Tr. Vol. 18, p. 44.

In the Commission's Additional Information Order, the Commission requested that DEC provide the following information:

> 8. Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEC will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.
>
> 9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

DEC's revised AMI cost-benefit analysis was attached to DEC's Second Responses and filed in the SGTP Docket on December 15, 2017, as Exhibit No. 2. The largest category of benefits included in the analysis continues to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of the NLLR benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis, which includes the cost of replacing AMI meters at the end of their 15-year useful life, shows that AMI deployment would result in net costs having a present value of $49.9 million (DEC's Second Responses, Exhibit No. 2).

DEC witness Schneider takes issue with the Commission's requirement that DEC include in its revised cost-benefit analysis the costs of replacing AMI meters at the end of their 15-year lives. Witness Schneider stated that this adjustment was not a conventional part of DEC's usual business case assessment. He opined that it essentially doubled the cost of the replacement meters over a 30-year period, but only accounted for the benefits of the meters for 15 years, the life of the current AMI meters being deployed by DEC. Tr. Vol. 18, pp. 408-14.

I am not persuaded by witness Schneider that the cost of replacing AMI meters at the end of their 15-year useful life should not be included in the AMI cost-benefit analysis. Public Staff witness Maness testified that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that this is the period of time that should be used to calculate DEC's annual AMR depreciation expense. Tr. Vol. 22, pp. 103-04. Further, there is no contention or evidence that DEC's AMR meters are not functioning properly or are not serving their intended purpose. Nevertheless, DEC is requesting that ratepayers pay for discarding the AMR meters and replacing them with AMI. In addition, the AMI meters being deployed by DEC were manufactured in 2009. Tr. Vol. 18, pp. 374-75. Based on these facts, it is reasonably likely that in 15 years, or perhaps sooner depending on further developments in AMI technology, DEC could be before the Commission requesting to scrap its 2009 AMI meters and to replace them with the latest metering technology. As a result, it is appropriate to include in DEC's cost-benefit analysis the cost of replacing in 15 years the AMI meters presently being deployed by DEC.

I conclude that the first cost-benefit analysis produced by DEC was not properly structured, and, therefore, it was not reasonable for DEC to rely on that analysis in deciding to fully deploy AMI. The first analysis was not properly structured because, as noted above, it did not include the cost of replacing the AMI meters after 15 years. In addition, DEC's first cost-benefit analysis was not properly structured because DEC used the EPRI 2% NLLR factor.

In the December 2008 EPRI Report, EPRI noted the following reasons for non-technical losses:

- Non-performing and under-performing meters.
- Incorrect application of multiplying factors.
- Defects in current transformer and potential transformer circuitry.
- Non-reading of meters.
- Pilferage by manipulating or bypassing meters.
- Theft by direct tapping and so on.

2008 EPRI Report, pp. 1-3.

With regard to the measurement of non-technical losses, the EPRI Report stated:

> Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the

> distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.
>
> Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty in obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable.

2008 EPRI Report, p. 1-7 (emphasis added).

The above discussion about the difficulty of quantifying NLLR is not convincing, particularly with regard to DEC. I accept the statement in the EPRI Report that "there is no firm data to define the level of losses on an industrywide basis." However, DEC had no reason to measure NLLR on an industrywide basis. DEC has been providing electric service in North Carolina for over 100 years. Consequently, DEC has a wealth of experience and knowledge about the components that make up NLLR, such as non-performing and under-performing meters, and theft losses. Therefore, it was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC's actual NLLR amount. As a result, with respect to determining the cost-effectiveness of DEC's AMI deployment, I give no weight to DEC's first cost-benefit analysis.

Instead, I give substantial weight to the revised cost-benefit analysis provided by DEC on December 15, 2017. The revised cost-benefit analysis, using DEC's actual NLLR numbers, is a reasonable and accurate methodology for projecting the costs and benefits of AMI, and, therefore, is probative evidence of such costs and benefits.

The majority gives substantial weight to DEC's evidence of future energy saving and peak shaving rate designs that can be supported by AMI. In DEC's Supplemental Filing, DEC discussed the possibility of additional customer services to be provided by AMI.

> [A]MI is the foundational investment that will enable enhanced customer solutions – giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy

> usage, and ultimately, their bills. Over time, the Company also expects AMI meters to contribute to cost reductions from reduced truck rolls in the years after deployments.

Supplemental Filing, p. 1.

In the Commission's SGTP Presentation Order, with regard to the above statement, question number 7 asked DEC to "Explain fully whether and how all of the costs for developing and deploying those services are included in the cost-benefit analysis." In response, DEC stated:

> No costs or benefits for developing and deploying additional customer programs/services were included in the AMI cost –benefit analysis.

DEC's First Responses, p. 8.

Nevertheless, during cross-examination by DEC's counsel witness Schneider stated:

> [t]here is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn't have those costs and benefits in our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

Tr. Vol. 18, pp. 413-14.

I give no weight to witness Schneider's testimony regarding possible new rate designs, additional customer programs and additional customer benefits not identified and not included in the cost-benefit analysis. DEC has the proverbial cart before the horse. Future possible rate designs and other measures that may be developed and that may provide customer benefits are much too speculative for the Commission to accept as probative evidence.

Public utilities are required to provide cost effective services. G.S. 62-2. DEC's revised AMI cost-benefit analysis shows that on a present value basis the cost of DEC's AMI deployment is $49.9 million more than the benefits. In addition, another major cost of DEC's AMI deployment is the lost value of DEC's AMR meters, which will be approximately $85 million.[78] The AMR meters still have 15 years of useful life and are serving their

[78] DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. However, in the SGTP presentation witness Schneider

intended purpose. Nevertheless, DEC would discard the AMR meters and recover the loss of the approximately $85 million book value from DEC's ratepayers.

Moreover, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs. The result would be that DEC's customers would be paying for AMI and AMR meters for the next 15 years. Yet, even under DEC's initial cost-benefit analysis, ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been scrapped by DEC. Based on the present value of the cost of DEC's AMI deployment being $49.9 million more than the benefits, the loss of 15 years of useful life of DEC's existing AMR meters, and the double meter costs that ratepayers would be required to pay for several years, I conclude that a preponderance of the evidence shows that DEC's AMI deployment is not a cost-effective method of providing service.

C. Prudence of DEC's AMI Implementation

In Docket No. E-2, Sub 537, the Commission addressed alleged imprudence by Carolina Power & Light (CP&L), DEP's predecessor, in the construction of the Shearon Harris Nuclear Plant. The Commission disallowed certain costs of construction based on its findings of imprudence by CP&L that resulted in unreasonable delays and avoidable errors in the construction of CP&L's Harris plant. 78 North Carolina Utilities Commission Orders and Decisions 238 (August 5, 1988) (Harris Order); reversed in part, and remanded (on other grounds), State ex rel. Utilities Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). The Commission stated the general standard of prudence as

> [w]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time (citation omitted)…The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted.

Harris Order, at 251-252.

As previously discussed, DEC's first cost-benefit analysis was not properly structured because it included DEC's use of the EPRI 2% NLLR factor. It was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC's actual NLLR experience. With respect to determining the prudence of DEC's AMI deployment, I give substantial weight to DEC's use of its first cost-benefit analysis in

testified that DEC would receive tax benefits that would reduce the lost book value to approximately $85 million. (SGTP Presentation, Tr., pp. 42-43.)

making the decision to deploy AMI. It was not reasonable for DEC to rely upon that analysis in deciding to fully deploy AMI and, therefore, DEC's decision to deploy AMI was not a prudent decision.

In addition, I give substantial weight to the testimony of Public Staff witness Maness that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that 15 years should be the length of time for recovering the AMR depreciation expense. The evidence in the present case does not support DEC's decision to discard AMR meters that are properly functioning and have 15 years of useful life, particularly when it leads to the unjust result that DEC's ratepayers pay the remaining $85 million book value of the AMR meters. DEC had all of this information in late 2016 when it made its decision to fully deploy AMI. In fact, DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. Thus, when DEC began deploying AMI meters in early 2017 DEC knew that its decision meant that ratepayers would be required to pay somewhere between $127 million and $85 million for discarded AMR meters. Based on these facts, it was not reasonable for DEC to decide in early 2017 to fully deploy AMI meters and to discard its AMR meters. Therefore, DEC's decision to deploy AMI was not a prudent decision.

Finally, as previously discussed, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs, which would result in DEC's customers paying for AMI and AMR meters for the next 15 years, even though under DEC's initial cost-benefit analysis ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been discarded by DEC. DEC had these facts when it decided to begin deploying AMI meters in early 2017. Based on these facts, at the time of the Company's decision in early 2017, it was not reasonable nor prudent for to deploy AMI meters and to discard its AMR meters.

Applying the Harris Order standard of prudence to the above facts, I conclude that a preponderance of the evidence shows that DEC's AMI deployment was not a prudent action when DEC began deploying AMI meters in early 2017. Therefore, I would deny DEC's request to recover its AMI costs, but authorize DEC to place its present AMI costs of $90.9 million and its future AMI costs in a deferred account, with no carrying charge, and to seek recovery of those costs in a future general rate case. In addition, I would require that DEC continue depreciating its AMR meters as presently scheduled, and remove AMR meters from rate base as they are replaced.

V. CONCLUSION

My conclusions in summary are these:

(a) that the Majority Order imposes on ratepayers a substantial amount of costs directly attributable to the Company's imprudent management of its waste coal ash impoundments at the Dan River plant, imprudence that produced the release of waste ash into the Dan River in February, 2014;

(b) that the Majority Order improperly shifts to present and future customers a substantial amount of costs for closure of the Company's waste coal ash impoundments that should have been charged and collected from prior customers for electricity service provided in the past;

(c) that the Majority Order, without proper analysis or foundation in law or in record evidence, impermissibly authorizes the Company to earn a return, or profit, from the deferred amounts expended by the Company in the period 2015 through 2017 for costs related to the closure of its waste coal ash impoundments;

(d) that the Majority Order, again without basis in the record and in a manner that unfairly discriminates among different classes of customers, permits the Company to increase the fixed monthly charge to its residential customers, even though the majority decision finds that the Company does not require any increase in revenue from residential customers or from any other class of customers; and

(e) that the Majority Order improperly permits the Company to include in its rates the costs of replacing existing customer meters with new advanced technology meters, even though the existing meters have not reached the end of their useful lives and the Company is not presently able to offer to customers any material benefits from the new advanced technology meters.

For these reasons, I cannot conclude that the rates that will follow from the Majority Order are just and reasonable as required by law. I therefore dissent. In addition, I join in the dissenting opinion filed in this matter by Commissioner ToNola D. Brown-Bland.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner ToNola D. Brown-Bland, concurring in part and dissenting in part:

I respectfully dissent in part from the majority opinion and join in the dissenting opinion of Commissioner Clodfelter with respect to the decision to allow an increase in the fixed monthly residential charge; the approval of cost recovery in this general rate case for both the deployment of Advanced Metering Infrastructure (AMI) meters and the depreciation of Advanced Meter Reading (AMR) meters being replaced by AMI deployment 15 years before the end of their useful life; and the approval of waste coal ash cost recovery such that the Company ultimately will be permitted the opportunity to recover over 97% of its total projected waste coal ash removal costs of $2.6 billion from the ratepayers of North Carolina, despite substantial evidence of the Company's imprudent choices and actions leading to the incurrence of certain specific and identifiable costs. It is my opinion that each of these decisions is contrary to the Commission's charge to make rates that are just and reasonable. See G.S. 62-2 and 62-130.

A. Fixed Monthly Residential Charge

I join in Commissioner Clodfelter's dissenting opinion to the extent he finds that the majority decision to increase the residential fixed charge from $11.80 to $14 is not supported by any evidence of record, let alone substantial evidence as is required for all Commission decisions pursuant to G.S. 62-65, and to the extent of the shortcomings and criticisms he finds regarding the majority's "subsidization" and "cost causation" rationales for increasing the fixed residential charge by $2.20 per month. I further point out that while the increase to $14.00 appears to be arbitrary, it just happens to be the same as the fixed residential customer charge adopted in the Commission's Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142, on February 23, 2018. (DEP Order).[79] In the DEP Order, $14.00 was the agreed upon amount accepted and settled upon in the Stipulation between the Public Staff and DEP. Given the cost evidence of record in the DEP case and the give-and-take of settlement negotiations leading to the Stipulation between the Public Staff and DEP, combined with the continued use and acceptance of the minimum system cost allocation method at the time of the Commission's decision, I found the

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[79]Choosing the monthly fixed cost charge for DEC based on the charge the parties stipulated to in DEP would not be in keeping with the requirement to set just and reasonable rates based on substantial evidence. As DEC witness Pirro testified, "Other utilities'' cost and rates are not relevant to a determination of DEC's rates." He explained that rates should be set based on examining a utility's own cost of service. Tr. Vol.19, p. 84.

Commission's acceptance of the stipulated $14.00 charge for the fixed cost portion of the residential rates reasonable for DEP and its customers.

In contrast, in the present DEC rate case, there is no settlement or stipulation of the Company's request to increase the monthly fixed charge, there is no substantial support in the record suggesting that the fixed cost attributable to the residential class has increased over what was supported and found reasonable when the Commission set the Company's current rates, and thus no substantial evidence that an increase in the fixed cost portion of the residential rate is appropriate at this time. Moreover, the Company's overall revenue requirement is being decreased in the present general rate case, suggesting that any alleged subsidy effect cited by the majority is already minimized to a degree by the lesser revenue requirement, alleviating the perceived need to increase the residential fixed charge in haste.

Additionally, while the majority states a concern about minimizing subsidization, its focus is unfairly and discriminatorily upon only the residential class of customers. The Company requested that the Commission increase the monthly fixed charge for all classes of customers including the non-residential classes. That the Company sought to increase non-residential fixed charges based on DEC's cost of service indicates the Company's position and belief that its current non-residential rates are not properly balanced between fixed charges and demand charges, and that it believes that interclass subsidization exists within the non-residential classes similarly to the subsidization it believes is present in the current rates for the residential class. The majority opinion brushes off this concern even though the Company was obviously aware that its subsidization and cost causation concerns should not apply to one class to the exclusion of others. Finally, while the majority has set the residential fixed charge at the same mark as it did in the DEP Order, DEC and DEP sought different levels of fixed cost charges for each of the two companies, recognizing them to have different cost structures. It is inexplicable that the majority would cause DEC ratepayers to pay the same fixed cost charge as DEP, when the evidence produced by the utilities in their respective cases tends to show that DEP's cost of service is higher than DEC's—an indication that the majority's decision is not based on actual costs.

With respect to the $14.00 fixed monthly residential charge sanctioned for DEC and its ratepayers, the majority opinion relies heavily on the concept that this charge strikes a proper balance and better reflects actual cost causation. However, no party presented evidence supporting $14.00 as the actual fixed residential cost of service. The majority claims to have chosen a cost number from within a range suggested by two different models for determining cost causation, but the evidence shows that the cost is either at the higher minimum system cost of $23.78 or at the lower basic customer cost method of $11.08. Choosing a random number between the two ends offered as evidence without a rational basis does not meet the Commission's obligation to set just and reasonable rates based on substantial evidence. <u>See</u> G.S. 62-65 and 62-131.

In addition, due to the flaws with and the need to review the use of the minimum system methodology which impacts the Company's rate design with respect to customer fixed cost charges (particularly in light of the likelihood that costly additions the Company plans to make to move its power system forward could have the effect of further increasing the fixed cost portion of the rates), I join in Commissioner Clodfelter's call first to have the benefit of access to the Commission-ordered evaluation of options for distribution system cost allocation and a study of consistent application of methodology prior to making any increase in the fixed monthly charge to residential ratepayers. As long as there is the reasonable possibility that after the Commission-ordered evaluation, the fixed distribution costs attributable to residential customer will be less than $14.00, it is unfair and unnecessary to increase this charge at this time given that in this general rate case the Commission has determined that the Company has no need for any additional revenue requirement. At this point in time, the increase in the fixed residential charge would appear to have more to do with stabilizing company revenues than with following cost causation principles or easing the burden of within-class subsidization through demand charges.

Accordingly, I find that the majority's increase of the monthly fixed residential charge is unjust and not reasonable based on the record before the Commission.

B. Recovery of Meter Costs

I join in Commissioner Clodfelter's dissent agreeing with him that DEC should not be allowed to recover AMI costs in this rate case but should instead be allowed to defer such costs until its next general case in which it could recover the deferred costs on producing substantial evidence that the Company's deployment of AMI meters is cost effective. I write to add that with the provisions that require the Company to move promptly to bring customers benefits from placing AMI meters in service such that ratepayers' likelihood of receiving value from paying for this new technology well before 2025, and before possible obsolescence of the new meters, is greatly increased, I would approve the Company's request to recover its AMI costs in this rate case, but for the majority's decision requiring ratepayers to continue paying for "new" and currently used and useful AMR meters at the same time they are to pay for new AMI meters. If the ratepayers were not required to pay for the AMR meters which still have a useful life of 15 years, I would find the decision to deploy AMI meters at this time prudent and cost effective.

It is patently unfair, unjust and unreasonable that the Company be allowed to make a unilateral decision stranding its own assets and then have the ratepayers pay for a decision within DEC's own control not only to strand its assets but also to strand them at a time when nearly $128 million in undepreciated value (reduced to $85 million by tax benefits) remained on the books. The majority's decision in essence means that ratepayers will be paying for two "shiny objects" at one time while they are able to use only one. There are certainly instances where allowing for recovery of stranded assets which represented a reasonable and prudent spend at the time of construction or deployment is the right decision, but when the utility's assets are stranded by its decision, made unilaterally on its own, and the assets are stranded with substantial useful life and functionality remaining, this is not one of those instances. I would protect the ratepayers from this situation and impose at least some of the cost for this decision to strand assets on the Company. There is no compelling evidence in the record that suggests that deploying AMI now and creating a stranded asset with many years of remaining useful life is necessary to the continued provision of safe, reliable, affordable and good quality service. It is unfair that ratepayers must continue paying for AMR for the next 15 years and not receiving benefit from those meters during a significant portion of that time period and also not receiving much additional benefit from the new replacement meters until some indefinite time in the future.

C. Recovery of coal ash basin closure costs

I join in the dissenting opinion of Commissioner Clodfelter and would allow recovery of some coal ash basin closure costs and deny others as he has well-detailed. I write to add that it is an unfair result that the majority's decision paves the way toward the ratepayers being responsible to pay over 97% of the Company's projected total waste coal ash removal costs of $2.6 billion in light of imprudent choices and actions by the Company that resulted in the incurrence of a significant portion of the costs now sought from the ratepayers.

Being imprudent or taking an action that is imprudent is not unlawful. On the other hand, committing an act that is unlawful, whether in violation of a criminal law, a regulation or a civil duty, is imprudent. Being imprudent with respect to an action or choice means being practically unwise, not careful, not cautious, or not circumspect. <u>See</u> <u>Black's Law Dictionary</u>, "Prudent," p. 1226 (West Publishing Co., 1990) (definition in pertinent part). The concept of imprudence is so basic and well-understood that we "know it when we see it" and analytic gymnastics is not required in order to recognize it. The same is true of imprudently incurred costs—these are costs that could have been avoided if the actor (in this case a utility), had made more cautious, wiser, or more careful decisions. A choice made could be a viable option, but still not have been a wise, prudent choice among viable approaches.[80]

Based on the entire record before the Commission, the record is replete with evidence of the Company's imprudent choices and acts of both commission and omission. Just a few examples in addition to those discussed in detail in Commissioner Clodfelter's dissenting opinion are the failure to take action to

[80] Under the North Carolina Public Utilities Act, imprudence on the part of a utility can be found without a showing or establishing of legal violation or breach of civil duty, but if either of those is established, such as by an admission of criminal negligence or by evidence in the record sufficient for a prima facie showing of civil negligence or of negligence *per se,* as I discussed in my dissent in Docket No. E-2, Sub 1142, Commission Order dated February 23, 2018, then a finding and conclusion of imprudence is proper and arguably required.

mitigate or eliminate groundwater contamination at Dan River at least as early as 2007, when based on its own knowledge as expressed in its own document entitled Environmental Management Program for Coal Combustion (Kerin AGO Cross Ex. 3), it should have realized the imprudence of a "minimum compliance with law" stance as opposed to taking actions it knew would have better protected surface and groundwater from contamination; the failure to heed the advice of its program engineers to provide a budget for camera inspection of stormwater pipes running under or through ash basins at the Dan River plant (Kerin AGO Cross Ex. 6); and the failure to follow its own closure plans to promptly begin dewatering the impoundments at Dan River following retirement of the coal units in 2012. Each of these actions or non-actions involved imprudent unwise decisions or choices and each led to specific identifiable costs that are included among the costs the Company and the majority would have the ratepayers pay nearly in their entirety.

Despite a record full of such examples of imprudence, the majority finds no imprudence and, therefore, fails to engage in the exercise of determining waste coal ash removal costs directly (much less indirectly) attributable to instances of imprudence on the Company's part. Not only does the record reveal imprudence in handling, storing, maintaining and monitoring waste coal ash just as it did in the DEP Rate Case, but as Commissioner Clodfelter explains, imprudent administrative and management decisions, such as not seeking recovery for basin closure costs in earlier rate cases, are also established by the evidence of record. Such decisions have led to some of the increased coal ash related costs being sought in this case from ratepayers far removed from the generation of ratepayers who received the benefit of electric service leading to the ash residue which is the subject of the costs sought by the Company today.

While, for many reasons, it is difficult and in some cases impossible to determine from the record all the costs attributable to the Company's imprudence, chasing perfection should not be allowed to become the enemy of the good. There is evidence in the record that permits identification and disallowance of specific discrete costs and/or cost increases caused by identifiable and known acts of imprudence. It is the better course of action, through disallowance of these costs, to have the ratepayers, who benefitted from affordable electricity service fueled by coal, and the Company and its shareholders reasonably share in the costs of waste coal ash removal and basin closure than to avoid the exercise of parsing through costs to distinguish between those that were prudently incurred and those that were not. An arbitrary monetary amount without rational basis chosen as a one-time management penalty cannot substitute for the Commission's duty to make rates that are fair to both the Company and its ratepayers on a case by case (incurrence by incurrence) basis considering all evidence of record in each individual case.

/s/ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland